NATIONAL ENERGY TECHNOLOGY LABORATORY

NETL

Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant

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Disclaimer

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Acronyms and Abbreviations

°F	Degree Fahrenheit
AEO	Annual Energy Outlook
AGR	Acid Gas Removal
ASTM	American Society for Testing and Material Standards
ASU	Air Separation Unit
AVB	Aluminum Vertical Break
Btu	British Thermal Unit
CBM	Coalbed Methane
CCF	Capital Charge Factor
CCS	Carbon Capture and Sequestration
CH_4	Methane
cm	Centimeter
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COE	Cost of Electricity
COS	Carbonyl Sulfide
CTG	Combustion Turbine/Generator
DOE	Department of Energy
DNR	Department of Natural Resources
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
g	Gram
G&A	General and Administrative
GHG(s)	Greenhouse Gas(es)
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
HC	Hydrocarbons
Hg	Mercury
HHV	Higher Heating Value

HRSG	Heat Recovery Steam Generator
I-6	Illinois No. 6
IGCC	Integrated Gasification Combined Cycle
IKP	University of Stuttgart
ISO	International Organization of Standardization
kg	Kilogram
kg/MWh	Kilogram per Megawatt Hour
km	Kilometer
kV	Kilovolt
kWh	Kilowatt-Hour
lb	Pound
LC	Life Cycle
LCA	Life Cycle Analysis
LCC	Life Cycle Cost
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
LCOE	Levelized Cost of Electricity
MACRS	Modified Accelerated Cost Recovery System
MMV	Measurement, Monitoring, and Verification
MPa	Megapascals
MW	Megawatt
MWe	Megawatts (electric)
MWh	Megawatt Hours
N_2O	Nitrous Oxide
NETL	National Energy Technology Laboratory
NH_3	Ammonia
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
O&M	Operations and Maintenance
O_3	Ozone
OSAP	Office of Systems, Analysis, and Planning
Pb	Lead

PM	Particulate Matter
psia	Pounds per Square Inch Absolute
PV	Present Value
R&D	Research and Development
RDS	Research and Development Solutions
ROM	Run-of-Mine
scf	Standard Cubic Feet
SF_6	Sulfur Hexafluoride
SO_2	Sulfur Dioxide
SO_X	Sulfur Oxide
STG	Steam Turbine Generator
TS&M	Transportation, Storage, and Monitoring
U.S.	United States
VOC	Volatile Organic Chemical

Executive Summary

Life Cycle Analysis (LCA) is a holistic methodology used to evaluate the environmental and economic consequences resulting from a process, product, or a particular activity over its entire life cycle. The Life Cycle, also known as cradle-to-grave, is studied within a boundary extending from the acquisition of raw materials, through productive use, and finally to either recycling or disposal. An LCA study can yield an environmental true-cost-of-ownership which can be compared with results for other alternatives, enabling a better informed analysis.

'Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant' case study evaluates the emissions footprint of the technology, including those from all stages of the Life Cycle. The stages include: fuel acquisition and transportation, the conversion of the fuel to energy, and finally the delivery of the energy to the customer. Also included in the study are the raw material and energy requirements. Additionally the energy cost contributions from each of these stages has been evaluated. The analysis examines two IGCC energy conversion cases. One case assumes that the IGCC facility will emit the full amount of carbon dioxide (CO_2) resulting from the utilization of the fuel (coal), which is assumed to be Illinois #6. The second case builds upon the first case by adding CO_2 removal capacity to remove 90 percent of the CO_2 from the power generation facility. The case that captures 90 percent of the CO_2 includes the additional capture equipment, compression equipment, pipeline and injection well materials and energy requirements.

Purpose of the Study

The purpose of this study is to model the economic and environmental life cycle (LC) performance of two integrated gasification combined cycle (IGCC) power generation facilities over a 30-year period, based on case studies presented in the NETL 2010 report, *Cost and Performance Baseline for Fossil Energy Plants: Volume 1* (NETL, 2010). It is assumed that both plants are built as new Greenfield Construction Projects. The NETL report provides detailed information on the facility characteristics, operating procedures, and costs for several IGCC facilities. In addition to the power generation facility, the economic and environmental performances of processes upstream and downstream of the power facility are considered.

Two IGCC cases are considered for evaluation:

- Case 1: (IGCC without CCS) - A 622-megawatt electric (MWe) (net power output) IGCC thermoelectric generation facility located in southwestern Mississippi utilizing Illinois No. 6 coal as a feedstock. This facility is equipped with control technologies to reduce emissions of nitrogen oxides (NO_X), sulfur compounds, particulate matter (PM), and mercury (Hg). This case is configured without carbon capture and sequestration (CCS).
- Case 2: (IGCC with CCS) - A 543-MWe (net power output) IGCC thermoelectric generation facility located in southwestern Mississippi utilizing Illinois No. 6 coal as a feedstock. This facility is also equipped with control technologies to reduce emissions of NO_X, sulfur compounds, PM, and Hg. In addition, a two-stage Selexol® solvent process is included to capture both sulfur compounds and carbon dioxide (CO_2) emissions. The

captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Scope of the Study

For this cradle-to-grave analysis, all stages of power generation are considered. The upstream LC stages (coal mining and coal transport) are modeled for both IGCC cases. The downstream LC stage (electricity distribution) is also included. Cost considerations provide the constant dollar levelized cost of delivered electricity (LCOE) and the total plant cost (TPC) over the study period. Environmental inventories include Greenhouse Gas emissions (GHG), criteria air pollutants, mercury (Hg), and ammonia (NH_3) emissions to air, water withdrawal and consumption, and land use (acres transformed). The GHG inventories were further analyzed using global warming potential (GWP) values from the Intergovernmental Panel on Climate Change (IPCC).

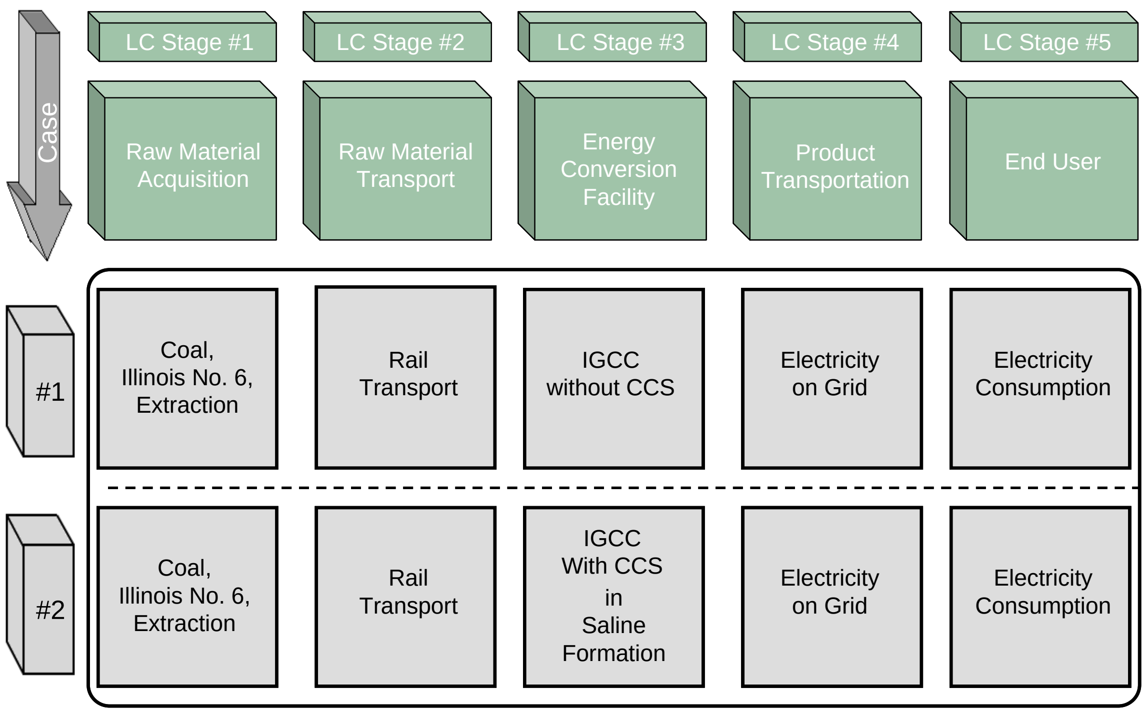

Figure ES-0.0-1 Comparison of Cases by Life Cycle Stage

Modeling Boundaries

Critical to the modeling effort is the determination of the extent of the boundaries in each Life Cycle (LC) stage. The individual LC stages for both cases are identified in **Figure ES-1**. The LC stages cover the following: the extraction of the coal at the coal mine, the transportation of the coal to the power plant, the burning of the coal and generation of electricity, the transmitting of electricity to the transmission and distribution (T&D) network, and the delivery of the electricity to the customer. The primary inputs and outputs along with the study boundaries are illustrated in **Figure ES-2** for the two cases. The specific assumptions made in the modeling are listed below:

- **LC Stage #1** includes the fuels used in the preparation and the decommissioning of the coal mine site, paving materials, materials for the buildings and the actual coal mining and handling equipment, energy and water for mining operations, land use considerations, and emissions. Capital and O&M costs of the coal mine are included in the minemouth cost of coal and are not explicitly defined.
- **LC Stage #2** includes the materials for the construction of coal unit trains, fuel for unit train operations, materials for the construction of the 25 miles of rail spur to the power plant, and emissions from the unit train. The main rail line between the coal mine and the power plant rail spur is not included in the modeling boundary, as it is assumed to previously exist. Coal cost data is a "delivered" price, so costs are not included from this stage.
- **LC Stage #3** includes the fuels used in the preparation and the decommissioning of the power plant site, materials for the buildings, power plant equipment, switchyards and transmission trunkline, fuel used in the power plant, Capital and O&M costs, electrical output and emissions from the power plant, and in the case for carbon capture and sequestration; equipment and infrastructure to capture, compress, transport, inject, and monitor CO2.
- **LC Stage #4** includes the delivery of the electricity to the customer, transmission line losses, and emissions of SF6 from power circuit breakers associated with the transmission line. The main transmission grid is not included in the modeling boundary as it is assumed to previously exist.
- **LC Stage #5** assumes all delivered electricity is used by a non-specific, 100% efficient process and is not included in the modeling.

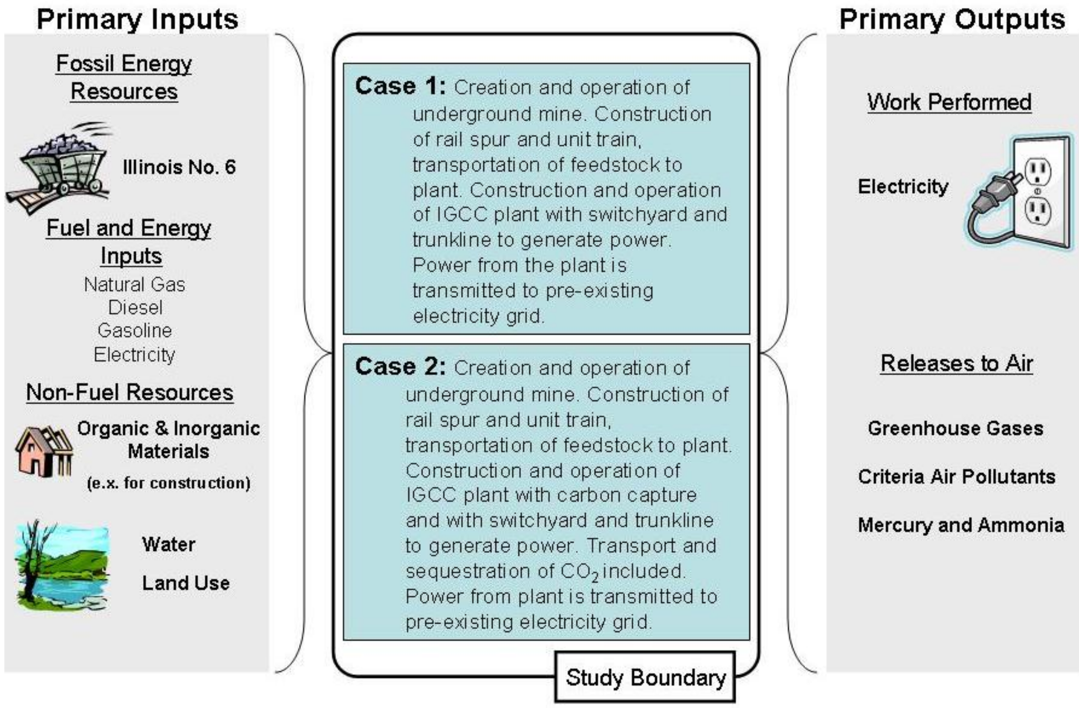

Figure ES-1.1-2 Study Boundary

Key Modeling Assumptions

Central to the modeling effort are the assumptions upon which the entire model is based. **Table ES-1** lists the key modeling assumptions for the IGCC with and without CCS cases. As an example, the study boundary assumptions indicate that the study period is 30 years, interest costs are not considered, and the model does not include effects due to human interaction. The sources for these assumptions are listed in the table as well. Assumptions originating in this report are labeled as "Present Study", while other comments originating in the NETL Cost and Performance Baseline for Fossil Energy Power Plants study, Volume 1: Bituminous Coal and Natural Gas to Electricity Report are labeled as "NETL Baseline Report."

Table ES-1 Key Modeling Assumptions

Primary Subject	Assumption	Source
Study Boundary Assumptions		
Temporal Boundary	30 years	NETL Baseline Report
Cost Boundary	"Overnight"	NETL Baseline Report
LC Stage #1: Raw Material Acquisition		
Extraction Location	Southern Illinois	Present Study
Coal Feedstock	Illinois No. 6	NETL Baseline Report
Mining Method	Underground	Present Study
Mine Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #2: Raw Material Transport		
Coal Transport Rail Round Trip Distance	1170 miles	Present Study
Rail Spur Constructed Length	25 miles	Present Study
Main Rail Line Construction	Pre-existing	Present Study
Unit Train Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #3: Power Plant		
Power Plant Location	Southern Mississippi	Present Study
IGCC Net Electrical Output (without CCS)	622.05 MW	NETL Baseline Report
IGCC Net Electrical Output (with CCS)	543.25 MW	NETL Baseline Report
Auxiliary Boiler Fuel	Natural Gas	Present Study
Trunk Line Constructed Length	50 miles	Present Study
CO_2 Compression Pressure for CCS Case	2,215 psi	NETL Baseline Report
CO_2 Pipeline Length for CCS Case	100 miles	Present Study
Sequestered CO_2 Loss Rate for CCS Case	1% in 100 years	Present Study
Capital and Operation Cost		NETL Bituminous Baseline
LC Stage #4: Product Transport		
Transmission Line Loss	7%	Present Study
Transmission Grid Construction	Pre-existing	Present Study

Summary Results

Figure ES-3 shows the comparison of LCOE components in $/kWh delivered energy. Overall, the cost of capital used to levelize has the largest impact on the results. The total LCOE results for the IGCC case with CCS (Case 2) exceed the LCOE results for the IGCC case without CCS

(Case 1) by 36 percent. It should be noted that the Life Cycle Costing model replicated the Stage #3 Energy Conversion Facility non-LC LCOE values of \$0.1088/kWh without- and \$0.1432/kWh with-CCS cases from the NETL Baseline Report when distribution loss was set to 0%. CO_2 T, S & M values do differ slightly with the NETL Baseline Report, as a different model approach was used in the Power LCA reports. Although each cost parameter (operation and maintenance [O&M], labor, utilities, and feedstocks) increases with the addition of CCS, the largest increase is for the capital cost component at 36 percent. The addition of CO_2 transmission, storage, and monitoring (TS&M) costs associated with CCS added 3.4 percent to the total resulting in a net increase in the overall LCOE for Case 2 to \$0.1620 per kilowatt hour (kWh).

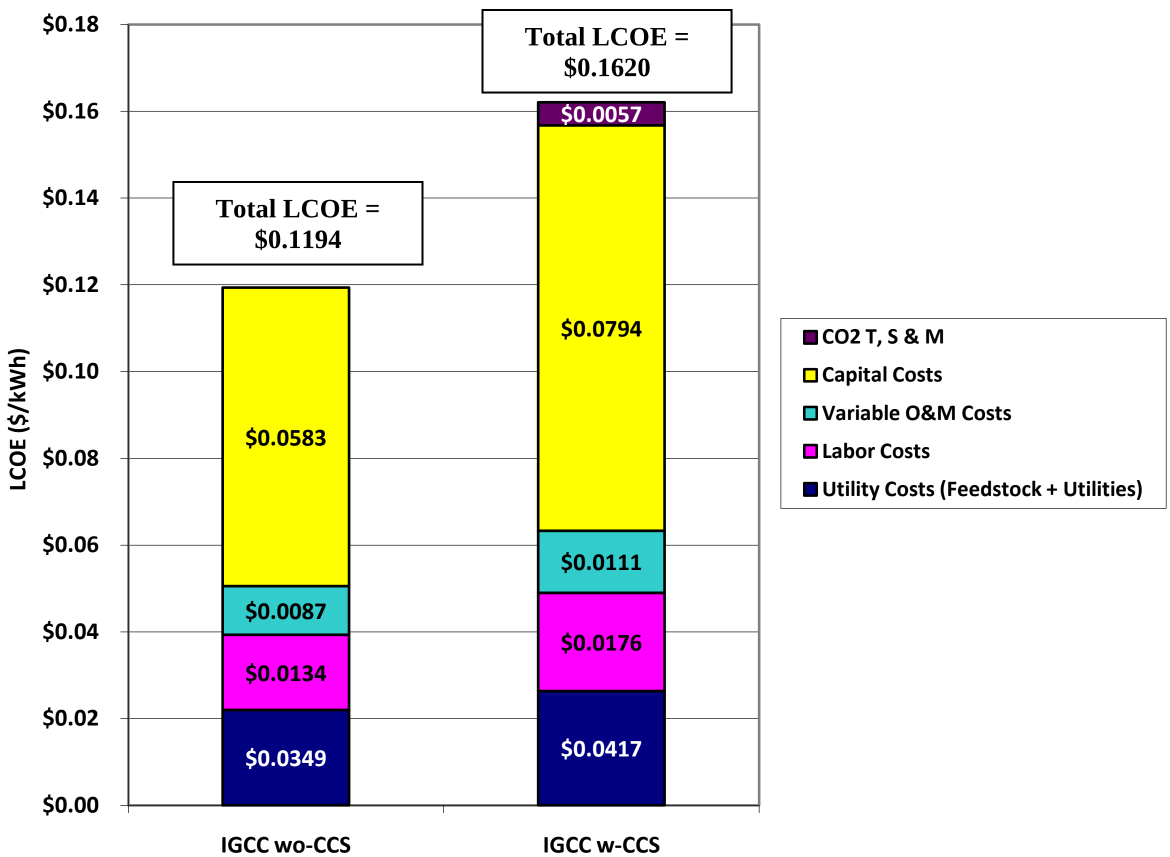

Figure ES-1.1-3 Comparative Levelized Cost of Delivered Energy (\$/KWh)

Table ES-2 compares the GHG emissions (kilogram [kg] CO_2-e/MWh (CO_2e per unit of delivered energy) for Case 1 (without CCS) and Case 2 (with CCS) for each stage and the overall LC. Methane (CH_4) emissions for Case 2 are slightly higher than Case 1 due to the increased coal input[1]. It is interesting to note that when considering Case 2, total CH_4 emissions (on a kg CO_2e basis) account for almost 40 percent of the total GHG emissions; much more than the eight percent impact of CH_4 in Case 1. Sulfur hexafluoride (SF_6) emissions are not seen as a large

[1] To model two IGCC plants with similar MWh outputs, the Baseline Report calculates a two percent increase in coal input for Case 2 (IGCC with CCS) (NETL, 2010). Even with additional coal resources, Case 2 still outputs less MWh than Case 1 (IGCC without CCS), but the two are as similar as possible considering equipment capacities and other factors (NETL, 2010).

contributor to the total GWP for either case, with a 1.5 percent impact to Case 2 and less than one percent for Case 1.

Table ES-2: Comparative GHG Emissions (kg CO_2e/MWh Delivered) for Case 1 (IGCC without CCS) and Case 2 (IGCC with CCS).

Emissions (kg CO_2e /MWh)	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: IGCC W/CCS	Stage #4: Transmission & Distribution	Total
Case 1-IGCC Without CCS					
CO_2	2.83	13.14	841.92	0.00	857.90
N_2O	0.01	0.01	0.01	0.00	0.03
CH_4	69.30	0.42	0.04	0.00	69.75
SF_6	1.5E-06	8.0E-07	7.0E-03	3.27	3.27
Total GWP	72.15	13.57	841.97	3.27	930.95
Case 2-IGCC With CCS					
CO_2	3.38	15.69	111.40	0.00	130.48
N_2O	0.02	0.01	0.01	0.00	0.04
CH_4	82.77	0.50	0.05	0.00	83.32
SF_6	1.8E-06	9.6E-07	8.1E-03	3.27	3.28
Total GWP	86.17	16.21	111.47	3.27	217.12

Overall, the addition of CCS to an IGCC facility reduces LC GHG emissions by approximately 77 percent. However, adding CCS increases the LC LCOE by 34 percent, including a 32 percent increase in capital cost. Other tradeoffs from the addition of CCS included more water and land use. Approximately 23 percent more water is needed during the carbon capture process for additional cooling. Additional land use is needed to install the CO_2 pipeline, which is assumed to impact forest land. Little impact was seen on non-GHG air emissions due to the addition of CCS; only minor increases were calculated due to additional coal needs for Case 2 (NETL, 2010).

Results from sensitivity analysis of LCC impacts offered further proof that capital costs have the largest impact on LCOE. Varying the capital costs ± 30 percent had an average of ± 17 percent impact on case 1 (without CCS), and a ± 18 percent impact on case 2 (with CCS). Feedstock and utility costs had a very small impact on LCOE, where varying from the AEO reference case to the high price case resulted in only a 0.02 percent change (EIA, 2008). LCI sensitivity was performed on CH_4 emissions from coal mining, train transport distance, and construction material inputs into Stage #1(raw material acquisition) and Stage #3 (energy conversion facility). Increasing construction material inputs by 3 times the base case values has minimal impact on GHG emissions. For non-GHG emissions some impact was seen on SO_2 emissions, but overall this sensitivity analysis showed that material inputs have little effect on the environmental LCI. Varying the CH_4 emissions to a maximum value (based on the average of historic [2002-2006] underground min data) resulted in a GWP of 9.6 and 1.9 percent for the with and without CCS cases, respectively (EPA, 2008b). When CH_4 emissions were reduced, assuming a 40% recovery at the coal mine, the GWP for case 2 (with CCS) decreased by 15 percent. However, this analysis does not consider other LC benefits or disadvantages associated with the recovery process, so additional modeling would need to be done before a conclusion can be drawn about its overall effectiveness. For IGCC without CCS, recovering CH_4 emissions at the coal mine only has a 3 percent impact on total GWP due to the large amount of CO_2 emitted during coal gasification. Rail transport distance did impact both GHG and non-GHG air emissions. Omitting rail transport (by cutting the distance between the mine and the IGCC facility from 1170 to 0 miles) decreased GWP by 4.4 and 7.5 percent for the without and with CCS cases, respectively. Significant decreases were also seen in total emission of NO_X, CO, and PM. The results of this sensitivity analysis validate the inclusion of raw material transport when considering the LCI impacts of a large energy conversion facility.

Key Results

- Adding 90 percent CO_2 capture and storage to an IGCC platform will increase the full life cycle LCOE from 11.9¢ to 16.2¢ – a 36 percent increase.

- GHG emissions for coal extraction and transport increase ever so slightly in Case 2 (IGCC with CCS), due to the increase in coal flow. However, the 90 percent CO_2 capture at the power plant results in a 77 percent reduction in total Life Cycle GHG emissions.

- The difference in LCOE, and GHG emissions between Case 1 and Case 2 result in a GHG avoided cost of \$59.68/tonne CO_2e.

1.0 Introduction

In 2008 the United States consumed approximately 41 quadrillion (10^{14}) British thermal units (Btu) of electricity per year, which is equivalent to 1.2 billion megawatt hours (MWh) per year of electricity generation (EIA, 2009). The 2009 Energy Information Administration's (EIA) Annual Energy Outlook (AEO) reference case projects a growth to 47.9 quadrillion Btu per year by 2030[2]. Although increasing concern about the negative environmental impacts associated with fossil fuel-based energy generation has prompted a 2.7 percent predicted annual increase in renewable energy electricity generation, AEO 2009 still expects that 66 percent of U.S. electricity will come from fossil fuels in 2030 (EIA, 2009). However, future greenhouse gas (GHG) legislation might require all carbon-intensive energy generation technologies to reduce emissions. Uncertainty about impending legislation has already prompted some investments in emerging energy generation technologies or retrofits will provide both environmental and economic benefits over existing technologies. Investors and decision makers need a concise way to compare the environmental and economic performance of current and existing generation technologies.

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has endeavored to quantify the environmental impacts and resource demands associated with building, operating, and retiring various thermoelectric generation technologies; both conventional and advanced technologies using fossil, nuclear, and renewable fuels. This quantification will be accomplished, in part through a series of life cycle analysis (LCA) studies. While NETL has performed LCA studies on selected electricity generation technologies in the past, an effort is underway to further expand this capability to achieve the highest possible assessment quality.

This report compares the economic and environmental life cycle (LC) performance of integrated gasification combined cycle (IGCC) electricity generation pathways, with and without carbon capture and sequestration (CCS) capability. IGCC is an emerging coal gasification technology, where benefits over conventional coal conversion may include increased efficiency and a reduction of some criteria pollutant emissions (NETL, 2008a). However, to fully quantify the difference (whether benefits or disadvantages) between IGCC and other generation technologies, the full environmental and economic performance needs to be evaluated over the LC of the system; the results of this LC evaluation provide a comparison point for competing electricity generating pathways assessed within NETL's LCA Program. **Figure 1-1** shows the economic and environmental boundaries of this LCA.

[2] These data were retrieved from the AEO 2009 early release; all cost data used in the report was taken from AEO 2008, as the full version of AEO 2009 was not released at the time that the cost modeling was completed.

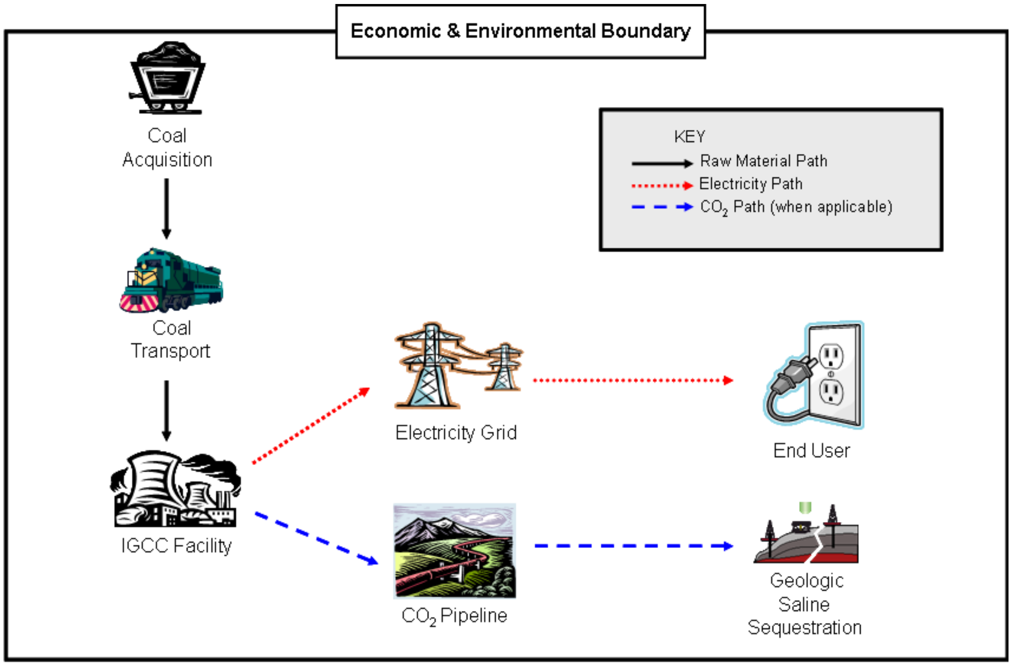

Figure 1.0-1 Conceptual Study Boundary

The following terms relating to LCA are used as defined throughout this document:

- Life Cycle (LC): Consecutive and interlinked stages of a product system, from raw material acquisition to the use stage.
- Life Cycle Inventory (LCI): The specific phase of the LCA which includes data collection, review, and verification; modeling of a product system to estimate emissions.
- Life Cycle Costing (LCC): The determination of cost parameters (levelized cost of electricity [LCOE] and net present value [NPV]) for the LCA throughout the study period.

1.1 Purpose

The purpose of this study is to model the economic and environmental LC performance of two IGCC power generation facilities based on case studies presented in the NETL 2010 report, *Cost and Performance Baseline for Fossil Energy Plants: Volume 1* (NETL, 2010). It is assumed that both plants are built as new greenfield construction projects. The NETL report provides detailed information on the facility characteristics, operating procedures, and costs for several IGCC facilities; data from the NETL report Case 1 and Case 2 were used significantly during this study. Throughout the remainder of this document, the NETL *Cost and Performance Baseline for Fossil Energy Plants: Volume 1* will be referred to as the "Baseline Report."

The following outlines the operating characteristics of the IGCC energy generation facility for each case:

- Case 1: A 622-megawatt electric (MWe) (net power output) IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A slurry of Illinois No. 6 (I-6) coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is cleaned in several steps utilizing carbonyl sulfide (COS) hydrolysis, mercury (Hg) capture, cyclone/candle filter particulate capture, and acid gas removal (AGR) before being fed to two advanced F-Class combustion turbine/generators (CTGs). The exhaust gas from each combustion turbine is fed to an individual heat recovery steam generator (HRSG) where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator (STG). A syngas expander generates additional power. This case is configured without CCS.
- Case 2: A 543-MWe (net power output) IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A mixture of I-6 coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is converted in a series of shift reactors to a hydrogen-rich gas and cleaned to remove Hg, acid gas, particulate matter (PM), and carbon dioxide (CO_2) utilizing a two-stage Selexol® solvent process. COS control is not necessary since that reaction occurs in the shift reactors. The clean gas is fed to two advanced F-Class CTGs. The exhaust gas from each combustion turbine is fed to an individual HRSG where steam is generated. All of the net steam generated is fed to a single conventional STG. A syngas expander generates additional power. This case is configured with CCS.

In additional to the energy generation facility, the economic and environmental performance of processes upstream and downstream of the facility will be considered. The upstream LC stages (coal mining and coal transport) will be the same for both IGCC cases; the case with CCS includes the additional transport and storage of the captured carbon. The study time period (30 years) will allow for the determination of long-term cost and environmental impacts associated with the production and delivery of electricity generated by coal gasification. Although not within the scope of this report, the overarching purpose of this study is to compare these results to other competing electricity generating pathways assessed within NETL's LCI&C Program.

1.2 Study Boundary and Modeling Approach

The following directives were used to frame the boundary of this study and outline the modeling approach:

- The basis (i.e., functional unit) of NETL electricity generation studies is defined generally as the net work (output from the process minus losses during the delivery and use of the product) in MWh over the 30-year study period. Therefore, for this study, the functional unit is the range of MWh output from both energy generation facilities (with and without CCS). To calculate results, the environmental and economic data from each stage was totaled, and then normalized to a 1-MWh basis for comparison. Additionally, results from each stage are reported on a unit process reference flow basis. For example, results from coal mining and coal transport are presented on a kilogram (kg) of coal basis, and results from energy conversion and electricity transmission are presented on a 1-MWh basis.
- All primary operations (defined as the flow of energy and materials needed to support generation of electricity from coal) from extraction of the coal, material transport, electricity generation, electricity transport, and end use were accounted for.
- Secondary operations (defined as inputs not immediately needed for the flow of energy and materials, such the material input for construction) that contribute significantly to mass and energy of the system or environmental or cost profiles are also included within the study boundary. Significance is defined in **Section 1.2.5**. Examples of secondary operations include, but are not limited to:
    - Construction of equipment and infrastructure to support each pathway (e.g., coal mine, power plant, transport equipment, etc.), with the exception of the power grid for electricity transport and end use being considered "pre-existing."
    - Provision of secondary energy carriers and materials (e.g., electrical power from the U.S. power grid, diesel fuel, heavy fuel oil, concrete production, steel production, etc.).
    - CO_2 transport and injection into the sequestration site.
- Construction of infrastructure (pipelines, railways, transmissions lines) is omitted from the study boundary if it is determined that they would exist without the construction of the studied facility or fuel extraction operation. For example, it is assumed that the transmission lines of the electrical grid would exist with or without the new energy conversion facility, and are thus not included in the model. However, the switchyard and trunkline, which connect the new energy conversion facility to the transmission lines/grid, would not exist without the new facility and are thus included in the LCI&C.

- Cost parameters will be collected for primary operations to perform the LCC analysis and will account for all significant capital and operating and maintenance (O&M) contributions.
- Detailed upstream cost profiles for secondary material and energy production are not required for the LCC analysis. Material purchase costs (for the secondary materials) are considered inclusive of upstream production costs in the final product cost.
- LCI will include, from each primary and significant secondary operation, the following magnitude evaluations: anthropogenic GHG emissions, criteria air pollutant emissions, Hg and ammonia (NH_3) emissions to air, water withdrawl and consumption, and land use. All emission results are reported in terms of mass (kg) released per functional unit and unit process reference flow, when applicable; water withdrawl and consumption are reported (by volume) on the same basis. Land use is reported as transformed land (type and amount [square meters] of land transformed).
- Indirect land use (or secondary land use effects) is not considered within the boundary of this study. Secondary land use effects are indirect changes in land use that occur as a result of the primary land use effects. For instance, installation of a coal mine in a rural area (primary effect is removal of agriculture or native vegetation and installation of uses associated with a coal mine) may cause coal mine employees to move nearby, causing increased urbanization in the affected area (secondary effect).
- If a process produces a co-product that, due to the purpose of the study, cannot be included within the study boundary, the allocation procedure will be determined using the following steps (in decreasing order of preference) as defined in International Organization of Standardization (ISO) 14044 (ISO, 2006):
    - Avoid allocation by either dividing the process into sub-processes or expanding the boundaries.
    - When allocation cannot be avoided, inputs and outputs should be divided among the products, reflecting the physical relationships between them.
    - When physical relationships do not establish basis for allocation, other relationships should be considered.

The following sections expand on the specific system boundary definition and modeling used for this study. Inputs and outputs from primary operations are shown in **Figure 1-2**. This simplified diagram illustrates how primary input materials move through the system, resulting in primary outputs

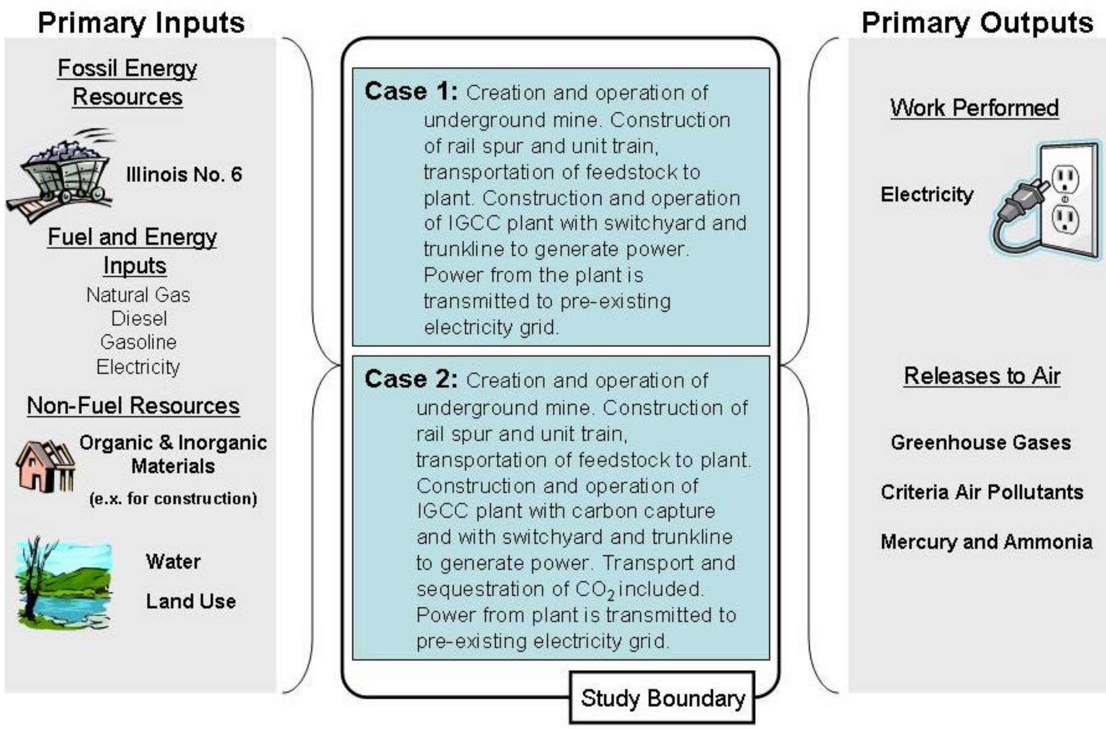

Figure 1.0-2 Study Boundary

1.2.1 Life Cycle Stages

The following text defines the LC stages considered in this study, and outlines specifications for the primary operations for each stage. Secondary operations are included based on data availability; if data is available the operation is included for completeness, if data is not available surrogate data is assumed or the operation is considered insignificance due to cut-off criteria specifications. Omissions due to data limitations are discussed in **Section 1.4**.

- **Life Cycle Stage #1:** Raw Material Acquisition: Coal Mining and Processing
  - Boundary begins with the opening of the coal mine and the extraction of the coal. All mining was assumed to be large-scale subterranean longwall mining of I-6 bituminous coal.
  - All major energy and materials inputs to the mining process (e.g., electricity use, fuel use, water withdrawals, chemical use, etc.) are considered for inclusion.
  - Capital and O&M costs of the coal mine are included in the minemouth cost of coal and are not explicitly defined (EIA, 2008).
  - Energy use and emissions associated with the commissioning and decommissioning of the mine are considered.
  - Boundary ends when the processed coal is loaded onto a railcar for transport to the IGCC facility.
- **Life Cycle Stage #2**: Raw Material Transport: Coal Transport

  - Boundary starts when the railcar has been loaded.
  - The diesel powered locomotive transports the coal to the IGCC facility, a distance of approximately 1,883 kilometers (km) (1,170 miles) round trip.
  - Railroad right-of-way and tracks are considered pre-existing. Installation of railcar unloading facilities and additional tracks connecting the facility to existing railroad lines is considered.
  - Boundary ends when the coal is delivered to the IGCC plant.
- **Life Cycle Stage #3**: Energy Conversion Facility: IGCC Plant
  - Boundary starts with coal entering the IGCC Plant, with or without CCS.
  - Construction and decommissioning of the plant structure are included.
  - Operation of the IGCC plant is included for both cases.
  - Capital and O&M costs are calculated for the operation of the plant for both cases.
  - Construction and operation are included for the switchyard and trunkline system that delivers the generated power to the grid.
  - For the IGCC plant with CCS, the boundary includes the following:
    - CO_2 is compressed to 2,215 pounds per square inch absolute (psia) at the IGCC plant. No additional compression is required during CO_2 transport or at the injection site.
    - Construction and operations of plant equipment required for CCS.
    - Construction and operation of a CO_2 pipeline from the plant site in southwestern Mississippi to a non-specific saline formation sequestration site 100 miles away. Losses of CO_2 from the pipeline during transport and injection are also included.
    - Construction of the pipeline for CO_2 injection at the sequestration site.
    - Costs associated with the operation of measurement, monitoring, and verification (MMV) of CO_2 sequestration at the sequestration site.
  - Boundary ends when the power created at the IGCC plant is placed onto the grid and CO_2 is verified and sequestered.
- **Life Cycle Stage #4**: Product Transportation: Electrical Grid
  - Boundary starts when the power is placed on the grid.
  - Electricity losses due to transmission and distribution are included.
  - Boundary ends when the power is pulled from the grid.

- **Life Cycle Stage #5**: End User: Electricity Consumption
    - Boundary starts and concludes when the power is pulled from the grid. All NETL power generation LCI&C studies assume electricity is used by a non-specific, 100 percent-efficient process.

The system boundary is consistently applied for all of the pathways included in the study. A comparison of the pathways by LC stage is depicted in **Figure 1-3.**

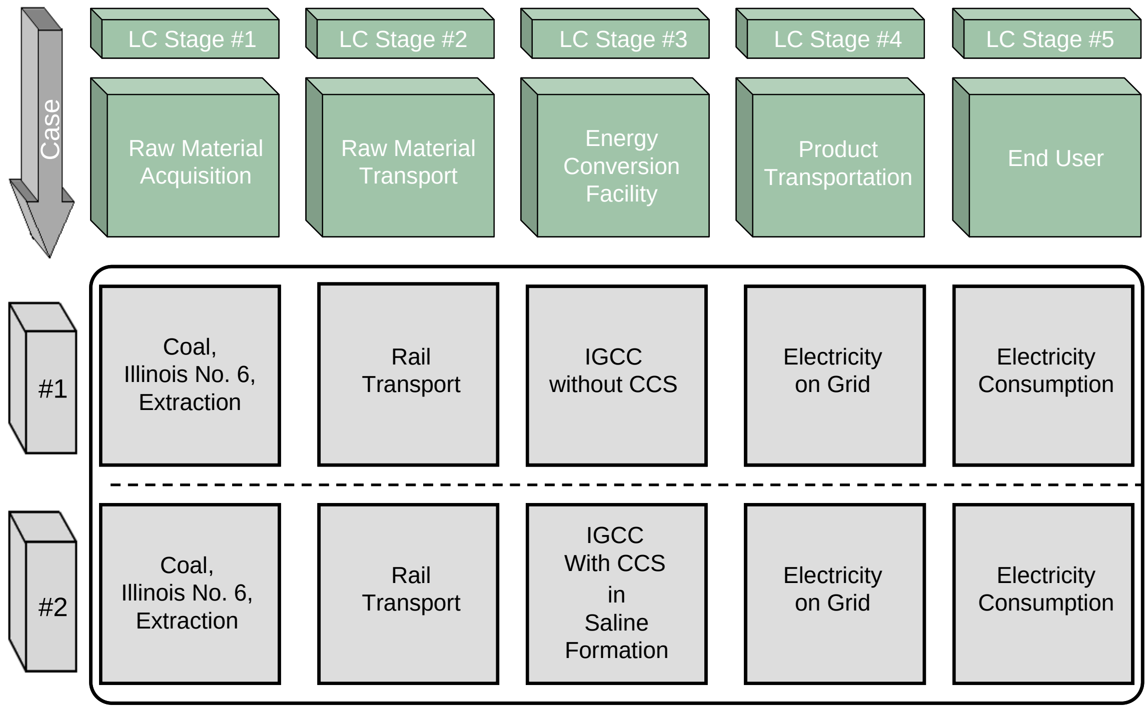

Figure 1.0-3 Comparison of Cases by Life Cycle Stage

Assessing the environmental LC perspective of each scenario requires that all significant material and energy resources be tracked back to the point of extraction from the earth (commonly referred to as the "cradle" in LCI terminology). While the primary material flow in this study is coal into electricity, many other material and energy inputs are considered significant and must be accounted for to accurately depict the LCI&C. These are considered secondary materials, and examples include concrete, steel, and combustion fuels such as diesel and heavy fuel oil. Cradle-to-grave (e.g., raw material acquisition through delivery of a finished product to the end user) environmental profiles for secondary materials are considered for all significant secondary material inputs.

1.2.2 Technology Representation

Currently, only five operational coal-based IGCC plants (>250 megawatts [MW]) exist in the world. Four of these, the Tampa Electric Co. Polk Power Station in Florida, the Wabash River plant in Indiana, the Puertollano plant in Spain, and the Buggenum plant in the Netherlands, have been in commercial operation for close to 10 years. The fifth plant at Nakoso, Japan, is now in the start-up phase. None of the aforementioned IGCC plants operate with carbon capture and sequestration. The removal of CO_2 from syngas streams has been demonstrated in chemical processes similar to that of an IGCC plant, but the sequestration part of the plant design has not been commercially proven. Certain aspects of the capture, such as integration of CO_2 removal in a complete IGCC plant, have yet to be demonstrated. However, for the purposes of this study, the CCS process as applied to an IGCC plant was assumed to be commercially available. The cost estimates for this case were taken directly from the Baseline Report and represent proven technology for CCS and the estimated cost for the IGCC plant (NETL, 2010).

1.2.3 Timeframe Represented

The economic and environmental profiles are compared on a 30-year operating time period, referred to as the "Study Period." The base year for the study was 2010 (e.g., Year 1) because the time required for plant and equipment construction would realistically happen before the following Year 1 assumptions were made. All capital investments were considered as "overnight costs" (assumed to be constructed overnight and hence no interest charges) and applied to Year 1 along with the corresponding O&M costs. Similarly, all environmental consequences of construction were assumed to occur on an overnight basis. All processes were thereby considered to be fully operational on day one of the 30-year study period. It was assumed that the life of all facilities and connected infrastructure is equal to that of the power plant.

1.2.4 Data Quality and Inclusion within the Study Boundary

High quality, transparent data were used for all inputs and outputs into each LC stage when available. To the greatest possible extent, transparent publicly available data sources were used to model each pathway. When available, data which was geographically, temporally, and technologically accurate was used for the LCI and LCC. However, that quality of data could not realistically be collected for each primary and secondary input and output into an LC stage. Therefore, the following additional data sources were used within this study:

- When publically available data were not available, purchasable, non-transparent data were use. For this study, purchasable data included secondary material LC profiles available from the GaBi modeling software database (GaBi data can be purchased publicly).
- In the event that neither public nor non-public data were available, surrogate data or engineered calculations were used.

When primary data (collected directly from operation of the technology being studied) was not available, uncertainty in data quality associated with geographic, temporal, or technological considerations was minimized using the following criteria:

- Data from the United States for similar processes were always preferred and used when available.
- Data for a process (or similar process) based on averages or best available technologies had to be dated from 1990 to present.
- European data were considered only for similar technologies or processes (consistent in scope and magnitude) when U.S. data were not available.
- If no data were available for the technology (or a reasonably similar technology), surrogate data were used.

Any data collected using an additional data source or different geographical, temporal, or technological specification was subject to uncertainty and sensitivity analysis depending on the significance of said data on the LC stage results. Sensitivity analysis results are discussed during interpretation of results (**Section 3.5**), and specific assumptions for each data input are listed by stages in **Appendix A**. Large data limitations specific to this study are listed in **Section 1.4**.

1.2.4.1 Exclusion of Data from the Life Cycle Boundary

Data were collected for each primary and significant secondary inputs and outputs to each LC stage (as defined by the system boundary) except the following, which for the reasons discussed were considered outside the boundary and scope of NETL power generation LCI&Cs.

Humans functioning within the system boundary have associated materials and energy demand as a burden on the environment. For humans working within the boundaries of this study, activities such as commuting to and from work and producing food are part of the overall LC. However, to consider such human activities would tremendously complicate the LC. First, quantifying the human-related environmental inflows and outflows would require a formidable data collection and analysis effort; second, the methodology for allocating human-related environmental flows to fuel production would require major assumptions. For example, if human activities are considered from a consequential perspective, it would be necessary to know what the humans would be doing if the energy conversion facility of this study did not exist; it is likely that these humans would be employed by another industry and would still be commuting and eating, which would result in no difference in environmental burdens from human activities with or without the energy conversion facility. For the LCC labor costs associated with the number of employees at each energy conversion facility was included.

Low-frequency, high-magnitude, non-predictable environmental events (e.g., non-routine/fugitive/accidental releases) were not included in the system boundaries because such circumstances are difficult to associate with a particular product. However, more frequent or predictable events, such as material loss during transport or scheduled maintenance shut downs, were included when applicable.

1.2.5 Cut-Off Criteria for the Life Cycle Boundary

"Cut-off criteria" defines the significance of materials and processes included in the system boundary and in general is represented as a percent of significance related to the mass, cost, or environmental burden of a system (ISO, 2006). If the input or output of a process is less than the given percentage of all inputs and outputs into the LC stage, then that process can be excluded. Whenever possible, surrogate or purchasable data assumptions were used as they are preferred over using a cut-off limit. However, when the cut-off criteria was used, a significant material input was defined as a material or environmental burden that has a greater than one percent per unit mass of the principal product of a unit process (e.g., 0.01 gram [g] per unit g). A significant energy input is defined as one that contributes more than one percent of the total energy used by the unit process. Although cost is not recommended as a basis to determine cut-off for LCI data, cost-based cut-off considerations were applicable to LCC data.

1.2.6 Life Cycle Cost Analysis Approach

The LCC analysis captures the significant capital and O&M expenses incurred by the IGCC cases with and without CCS for their assumed 30-year life. The LCC provides the constant dollar levelized cost of electricity (LCOE) of the production and delivery of energy over the study period (in years).

Cash flow is affected by several factors, including cost (capital, O&M, replacement, and decommissioning or salvage), book life of equipment, Federal and state income taxes, tax and equipment depreciation, interest rates, and discount rates. For NETL LCC assessments, Modified Accelerated Cost Recovery System (MACRS) deflation rates are used. O&M cost are assumed to be consistent over the study period except for the cost of energy and feedstock materials determined by EIA.

Capital investment costs are defined in the Baseline Report as including "equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project)." The following costs are excluded from the Baseline Report definition:

- Escalation to period-of-performance.
- All taxes, with the exception of payroll taxes.
- Site-specific considerations (including, but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.).
- Labor incentives in excess of a five-day/10-hour workweek.
- Additional premiums associated with an Engineer/Procure/Construct (EPC) contracting approach.

The capital costs were assumed to be "overnight costs" (not incurring interest charges) and are expressed in 2007 dollars. Accordingly, all cost data from previous reports and forthcoming studies are normalized to 2007 dollars. In accordance with the Baseline Report, all values are reported in January 2007 dollars; it is the assumption of this study that there is no difference between December 2006 dollars and January 2007 dollars. **Table 1-1** summarizes the LCC economic parameters that were applied to both pathways.

Table 1-1: Global LCC Analysis Parameters

Property	Value	Units
Reference Year Dollars	December 2006/January 2007	Year
Assumed Start-Up Year	2010	Year
Real After-Tax Discount Rate	10.0	Percent
After-Tax Nominal Discount Rate	12.09	Percent
Assumed Study Period	30	Years
MACRS Depreciation Schedule Length	Variable	Years
Inflation Rate	1.87	Percent
State Taxes	6.0	Percent
Federal Taxes	34.0	Percent
Total Tax Rate	38.0	Percent
Fixed Charge Rate Calculation Factors		
Capital Charge Factor	0.1773	--
Levelization Factor	1.42689	--
Start Up Year (2010) Feedstock & Utility Prices	*$2006*	
Natural Gas[1]	6.76	$/MMBtu
Coal[2]	1.51	$/MMBtu
Process Water[3]	0.00049 (0.0019)	$/L ($/gal)

1. AEO 2008 Table 3 Energy Prices by Sector and Source: Electric Power-Natural Gas (EIA, 2008).
2. AEO 2008 Table 112 Coal Prices by Region and Type: Eastern Interior, High Sulfur (Bituminous). To account for delivery of the coal, 25% was added to the minemouth price.
3. Rafelis Financial Consulting, PA. Rafelis Financial Consulting 2002 Water and Wastewater Rate Survey, Charlotte, NC.

The LCC analysis uses a revenue requirement approach, which is commonly used for financial analysis of power plants. This approach uses the cost of delivered electricity (COE) for a comparison basis, which works well when trying to evaluate different plant configurations. COE is levelized over a 20-year period, although the plant is modeled for a 30-year lifetime. The method for the 20-year LCOE is based on the NETL Power Systems Financial Model (NETL, 2008b). The LCOE is calculated using the PV costs. All PV were levelized using a capital charge factor (CCF) for capital costs and a levelization factor for O&M costs. The LCOE is determined using the following equation from the Baseline Report (NETL, 2010).

$$LCOE_P = \frac{(CCF_P)(TOC) + (LF)[(OC_{F1}) + (OC_{F2}) + \ldots] + (CF)(LF)[(OC_{V1}) + (OC_{V2}) + \ldots]}{(CF)(MWh)}$$

where

$LCOE_P$ = levelized cost of electricity over P years, $/MWh

P = levelization period (e.g., 10, 20 or 30 years)

CCF_P = capital charge factor for a levelization period of P years (0.1773 for IGCC)

TOC = total overnight cost, $

LF = levelization factor (a single levelization factor is used in each case because a single escalation rate is used for all costs) (1.426885 for IGCC)

OC_{Fn} = category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)

CF = plant capacity factor

OC_{Vn} = category n variable operating cost at 100 percent CF for the initial year of operation (but expressed in "first-year-of-construction" year dollars)

MWh = annual net megawatt-hours of power generated at 100 percent CF

1.2.7 Environmental Life Cycle Inventory and Global Warming Impact Assessment Approach

The following pollutant emissions and land and water resource consumptions were considered as inventory metrics within the study boundary:

- GHG Emissions: CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6) are included in the study boundary.
- Criteria air pollutants are designated as such because permissible levels are regulated on the basis of human health and/or environmental criteria as set forth in the Clean Air Act (EPA, 1990). Six criteria air pollutants are currently monitored by the EPA and are therefore included in the LCI of current NETL LCI&C studies, as shown in **Table 1-2**.

Table 1-2: Criteria Air Pollutants Included in Study Boundary

Emissions to Air	Abbreviation	Description
Carbon Monoxide	CO	--
Nitrogen Oxides	NO_X	Includes NO_2 and all other forms of nitrogen oxides.
Sulfur Dioxide	SO_2	Includes SO_2 and other forms of sulfur oxides.
Volatile Organic Compounds	VOCs	VOCs are also reported as non-CH_4 VOCs to avoid double counting with reported methane emissions.
Particulate Matter	PM	Includes all forms of PM: PM_{10}, $PM_{2.5}$, and unspecified mean aerodynamic diameter.
Lead	Pb	--

- Air emissions of Hg and NH_3 are included within the study boundaries due to their potential impact when assessing current and future electricity generation technologies.
- Water (withdrawal and consumption) is included within the study boundary, including that extracted directly from a body of water (above or below ground) and water obtained from municipal or industrial water source. The amount of water required to support a procedure or process can be discussed in terms of withdrawal or consumption. Within NETL LCI&C studies, water withdrawal is defined as the total amount of water that is drawn from an outside source in support of a process or facility. For instance, water wthdrawal for an energy conversion facility would include all water that is supplied to the facility, via municipal supply, pumped groundwater, surface water uptake, or from another source. Water consumption is defined as water withdrawal minus water discharged from a process or facility. For instance, water consumption for an energy conversion facility would be calculated by subtracting the amount of liquid water discharged by the facility from the facility's water withdrawal.
- Transformed land area (e.g., square meters of land transformed) is considered in NETL LCI&C studies for primary land use change. The transformed land area metric estimates the area of land that is altered from a reference state. Land use effects are not discussed for each stage in **Section 2.0**; the methodology and results for this inventory are discussed in **Section 3.3**.

The only impact characterized in this study is global warming potential (GWP). The final quantities of GHG emissions for each gas included in the study boundary were converted to a common basis of comparison using their respective GWP for a 100-year time horizon. These factors quantify the radiative forcing potential of each gas as compared to CO_2. The most recent 100-year GWP values reported by the Intergovernmental Panel on Climate Change (IPCC) are listed in **Table 1-3** (IPCC, 2007).

Table 1-3: Global Warming Potential for Various Greenhouse Gases for 100-Yr Time Horizon (IPCC, 2007)

GHG	2007 IPCC GWP (CO_2e)
CO_2	1
CH_4	25
N_2O	298
SF_6	22,800

The purpose of this study and all other NETL electricity generation studies is to perform and publish transparent LCI&C studies. Assuming this goal is achieved, any impact category related to the studied LCI data metrics can be applied to the results. Thus, while it was not within the scope of this work to apply all available impact assessment methods, others can use this work to apply impact assessment methods of their own choosing.

1.3 Software Analysis Tools

The following software analysis tools were used to model each of the study pathways. Any additional modeling conducted outside of these tools is considered a "data source" used to inform the analysis process.

1.3.1 Life Cycle Cost Analysis

An LCC model was developed as part of this study to calculate the LCOE ($/MWh) for each of the scenarios. The LCC model was developed in Microsoft® Excel to document the sources of economic information, while ensuring that all pathways utilize the same economic factors. The model calculates all costs on an LC stage basis, and then sums the values to determine the total LCC. This process enables the differentiation of significant cost contributions identified within the LCC model.

Research and Development Solutions LLC (RDS), as part of the project effort, developed the LCC model in-house. The LCC model leverages the experience gained in developing a similar cost model in the previous LCI&C studies conducted by NETL.

1.3.2 Environmental Life Cycle Inventory

GaBi 4, developed by the University of Stuttgart (IKP) and PE INTERNATIONAL of Germany, was used to conduct the environmental LCI. GaBi 4 is an ISO 14040 compliant modular software system used for managing large data volumes. In addition to adding data for a specific study into the GaBi framework, one can make use of the large database of LCI profiles included in GaBi for various energy and material productions, assembly, transportation, and other production and construction materials that can be used to assist in modeling the LC of each pathway. The GaBi 4 software has the ability to analyze the contribution from an individual process or groups of processes (referred to as "Plans") to the total LC emissions. Plans, processes, and flows form modular units that can be grouped to model sophisticated processes, or assessed individually to isolate effects. The GaBi system follows a process-based modeling approach and works by performing comprehensive balancing (mass and energy) around the various processes within a model. GaBi 4 is a database-driven tool designed to assist LCI practitioners in documenting, managing, and organizing LCI data. Data pulled from the GaBi 4 database and used within this study was considered non-transparent and was subject to sensitivity analysis. For this study, only secondary (or higher order) operations are characterized using GaBi profiles; all primary data were characterized by an additional reference source (peer reviewed journal, government report, manufacturer specifications, etc.) and entered into the GaBi framework.

1.4 Known Data Limitations Identified through Literature Review

A few LC studies on IGCC power generation are available in the literature, some of which are referenced here (Doctor, Molburg *et al.*, 2001; Capentieri, Corti *et al.*, 2005; Viebahn, Nitsch *et al.*, 2007); however, all have limitations. Because only a few IGCC plants are commercially operational, a limited amount of plant-level data is available which limits the amount of primary data available for LCI. Furthermore, existing LCI documents on power plants discuss GHGs, but often analyze and provide data only for CO_2. Similarly, evaluations of criteria pollutants focus on sulfur oxides (SO_X) and nitrogen oxides (NO_X), while neglecting other pollutants. Data for environmental issues on water emissions and land use is limited in these studies; data were pulled from other studies (coal-based plants) or estimated based on other relevant data sources and/or assumptions. Finally, although ISO guidelines are mentioned in most studies, it is not clear if they are specifically followed.

1.5 Summary of Study Assumptions

Central to the modeling effort are the assumptions upon which the entire model is based. **Table 1-4** lists the key modeling assumptions for the IGCC with and without CCS cases. As an example, the study boundary assumptions indicate that the study period is 30 years, interest costs are not considered, and the model does not include effects due to human interaction. The sources for these assumptions are listed in the table as well. Assumptions originating in this report are labeled as "Present Study", while other comments originating in the NETL Cost and Performance Baseline for Fossil Energy Power Plants study, Volume 1: Bituminous Coal and Natural Gas to Electricity Report are labeled as "NETL Baseline Report."

Table 1-4: Study Assumptions by LC Stage

Primary Subject	Assumption	Source
Study Boundary Assumptions		
Temporal Boundary	30 years	NETL Baseline Report
Cost Boundary	"Overnight"	NETL Baseline Report
LC Stage #1: Raw Material Acquisition		
Extraction Location	Southern Illinois	Present Study
Coal Feedstock	Illinois No. 6	NETL Baseline Report
Mining Method	Underground	Present Study
Mine Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #2: Raw Material Transport		
Coal Transport Rail Round Trip Distance	1170 miles	Present Study
Rail Spur Constructed Length	25 miles	Present Study
Main Rail Line Construction	Pre-existing	Present Study
Unit Train Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #3: Power Plant		
Power Plant Location	Southern Mississippi	Present Study
IGCC Net Electrical Output (without CCS)	622.05 MW	NETL Baseline Report
IGCC Net Electrical Output (with CCS)	543.25 MW	NETL Baseline Report
Auxiliary Boiler Fuel	Natural Gas	Present Study
Trunk Line Constructed Length	50 miles	Present Study
CO_2 Compression Pressure for CCS Case	2,215 psi	NETL Baseline Report
CO_2 Pipeline Length for CCS Case	100 miles	Present Study
Sequestered CO_2 Loss Rate for CCS Case	1% in 100 years	Present Study
Capital and Operation Cost		NETL Bituminous Baseline
LC Stage #4: Product Transport		
Transmission Line Loss	7%	Present Study
Transmission Grid Construction	Pre-existing	Present Study

1.6 Report Organization

This study includes two comprehensive LCI and cost parameter studies for electricity production via IGCC with and without CCS. The methodology, results, and conclusions are documented in the following report sections:

Section 1.0 – Introduction: Discusses the purpose and scope of the study. The system boundaries for each pathway and LC stages are described, as well as the study modeling approach.

Section 2.0 – Life Cycle Stages LCI and Cost Parameters: Provides an overview of each LC stage and documents the economic and environmental LC results. For both cases, all stages are the same except for Stage #3; a description and results for Stage #3 of both cases will be included in this section.

Section 3.0 – Interpretation of Results: Detailed analysis of the advantages and disadvantages of IGCC electricity generation with and without CCS. Analysis includes comparison of metrics (criteria air pollutants, Hg and NH_3 emissions to air, water and land use), GWP impact assessment, and sensitivity analysis results.

Section 4.0 – Summary: Discusses the overall study results and conclusions.

Section 5.0 – Recommendations: Provides suggestions for future improvements to the evaluation of LCC and environmental emissions related to complex energy systems as well as recommendations on areas for further study.

Section 6.0 – References: Provides citation of sources (government reports, conference proceedings, journal articles, websites, etc.) that were used as data sources or references throughout this study.

Appendix A – Process Modeling Data Assumptions and GaBi Modeling Inputs: Detailed description of the modeling properties, assumptions, and reference sources used to construct each process and LC stage. All modeling assumptions are clearly documented in a concise and transparent manner.

2.0 Life Cycle Stages: LCI Results and Cost Parameters

For each of the following LC stages, key details on LCI and LCC data assumptions for all major processes used to extract and transport coal, convert coal to electricity using gasification, capture and sequester CO_2 (when applicable), and transmit electricity are discussed. Additional, the environmental metrics (GHG emissions, criteria air pollutant emissions, Hg and NH_3 emissions, water (withdrawal/consumption), and land use) will be quantified for each stage. The LCC results will be given for Stage #3 only; assumptions for Stage #1 and Stage #2 are not quantified until Stage #3, and the COE at the end of Stage 5 can be assumed equal to the cost calculated at the gate of the conversion facility. All stages are applicable to both cases except Stage #3, where the description and results will be discussed for Case 1 and Case 2 separately. Discussion of Stage #4 and Stage #5 will be combined.

2.1 Life Cycle Stage #1: Raw Material Extraction

The following assumptions were made when modeling Stage #1:

- All mining was assumed to be large-scale underground longwall mining of I-6 bituminous coal.
- The mining took place in Southern Illinois.
- Information from the Galatia Mine was used as representative data for the mine characterized in this study.

The Galatia Mine was chosen based on its similarities with the studied mine, as well as the wealth of information available in the literature and through phone interviews with mine staff (DNR, 2006; EPA, 2008a). Galatia Mine is an underground mine with longwall operation located in Galatia, Illinois. Galatia Mine uses heavy media separation in its preparation plant. Of the four coal ranks (anthracite, bituminous, subbituminous, lignite), bituminous coal is the most abundant and has properties which make it conducive to usage (DOE, 2002).

Longwall mining and room-and-pillar mining are the two most commonly employed methods of underground coal mining in the United States. In contrast to the room-and-pillar mining method, in which "rooms" are excavated from the mine seam and "pillars" are left in place between rooms to support the mine roof, longwall mining results in extraction of long rectangular blocks or "panels" of coal, allowing the roof to collapse following coal extraction (EIA, 1995). The large-scale, continuous, and semi-automated nature of longwall mining makes average longwall mining operations more productive than traditional room-and-pillar operations. Longwall mining has also been proven safer than room-and-pillar mining; however, longwall mining does have higher capital costs and large amounts of dust and methane are generated during the mining process (EIA, 1995). Even with the disadvantages, longwall continues to grow as a common mining technology in the United States, recently accounting for 49.2 percent of coal mined (EIA, 2007a). For this study, longwall mining was considered the primary mining technology. However, before longwall mining can begin, the mine workings must be prepared; the panel is "blocking out" by excavating passageways and staging areas around the perimeter of the panel to be mined (see **Error! Reference source not found.**). Blocking ut is a room-and-pillar type operation that can be accomplished using a coal-cutting machine referred to as a continuous miner.

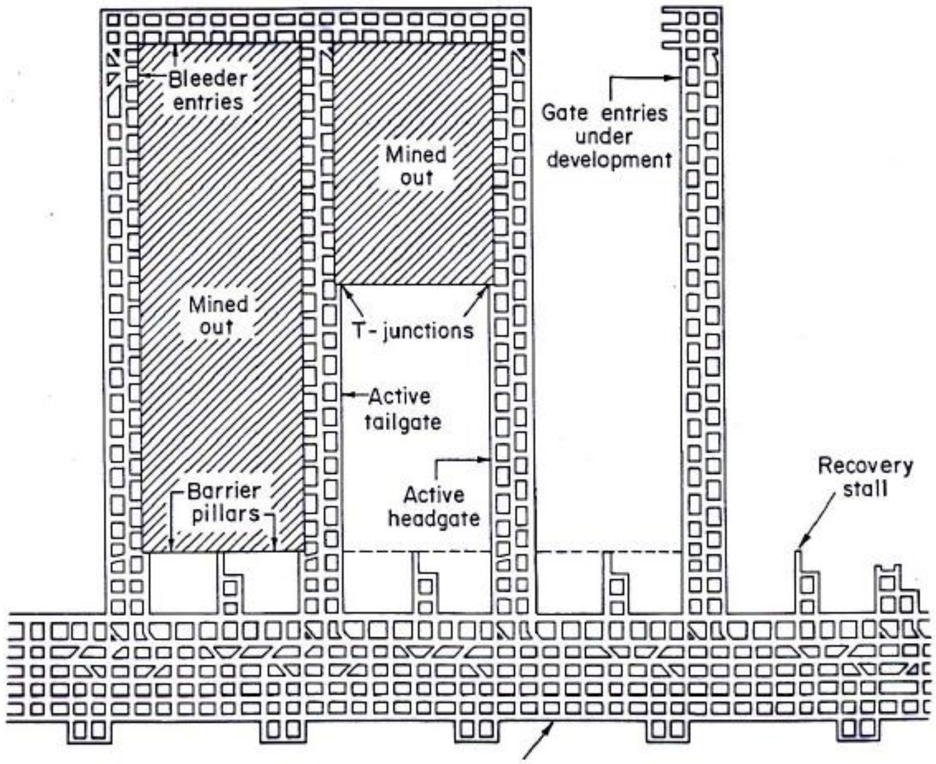

Figure 2-1 Setup, Operation, and Maintenance of the Longwall Unit Requires Preliminary Preparation of Access Entries and Staging Rooms that are Excavated Using Continuous Mining Machines-Overhead View (Mark 1990)

Following mining, coal from both types of equipment is conveyed from the mine using an electrically driven slope conveyance system. At the surface, coal is transferred from the slope conveyor to large electrically driven stacking machinery that stockpiles the run-of-mine (ROM) coal adjacent to the coal cleaning facility. Stockpiled ROM coal is then fed into the coal comminution (size reduction) and cleaning facility. Cleaned and dewatered coal is transferred to a storage silo located near the cleaning facility where the cleaned coal is then transferred from the storage silo to the railcar for transport. Reject material is partially dewatered and transferred to an onsite impoundment for storage. A simplified process schematic is shown in **Figure 2-2**.

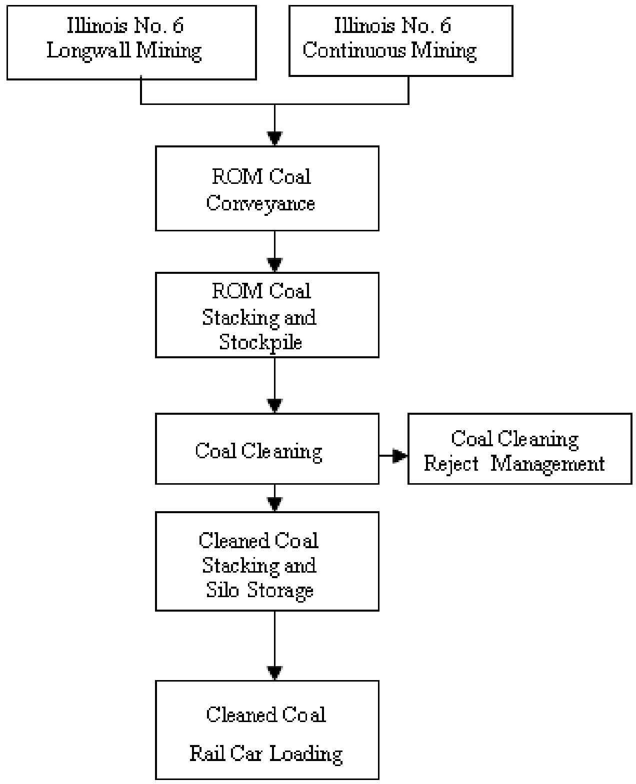

Figure 2-2: Simplified Schematic of Illinois No. 6 Bituminous Coal Mining, Processing, and Management

Major operations during Stage #1 include the mining equipment (longwall and continuous), material moving, and coal preparation (size reduction and cleaning). Most of the energy consumed during mining was due to the operation of electrically driven machinery; however, some diesel fuel use was assumed to be used during installation of the mine and for moving materials around the mine site. Besides combustion emissions, PM, CH_4, and Hg are also environmental outputs from a coal mine. Of the coal mined, a reject rate was assumed from Galatia Mine data to be 45 percent, which is lost during coal preparation and loading. Land use change was due to the creation of the underground mine and appurtenant surface facilities on greenfield land in southern Illinois. The coal cleaning operation dominated water withdrawal and consumption during mining activities.

2.1.1 LCC Data Assumption

The following text defines assumptions made to determine the cost of producing coal in Stage #1. Because the coal is not used until gasification at the plant site, no cost modeling results are necessary for this stage. All cost model results are reported in the Stage #3 LCC data results sections. AEO values were used for feed/fuel costs (i.e., fuel used as inputs to a unit process or LC stage) over the lifetime of the plant, beginning in 2010 and ending in 2040 (EIA, 2008). The AEO forecasts to 2030, so the final 10 years of the plant’s lifetime were extended beyond 2030 using regression of feedstock and other utility prices. All AEO values are in 2006 dollars. AEO 2008 Reference Case Coal

Prices by Region and Type Table (Table 112) was used to account for the coal prices for the first 20 years of the plant (EIA, 2008). These are minemouth costs for coal. The AEO 2008 reference case predicts a growth of 2.4 percent/year for the U.S. economy between the study period of 2006 to 2030 (EIA, 2008). In order to reflect the uncertainty associated with projection economic growth, AEO 2008 also includes high and low economic growth cases. The high case assumes higher growth in population, labor force, and productivity. This in turn lowers inflation and interest rates, increasing investment, disposable income, and industrial production. This all results in a three percent/year increase in economic output compared to 2.4 percent for the reference case. Conversely, the low case assumes the opposite; with less growth in population, labor, and productivity resulting in an economic growth of only 1.8 percent per year. **Figure 2-3** shows the AEO reference and high case prices for coal (higher heating value [HHV] basis) until 2030 and forecasted prices from 2031 to 2040. The initial decline in the extended data is due to the slope of the linear regression, which on average is less than the slope over the last years of AEO predictions; this is recognized as a simplification. This study assumed AEO reference case prices as the primary LCC modeling data set and used the high case prices to analyze the sensitivity of the LCC to variation in feed/fuel costs; low growth case values were not readily available in the LCC model and therefore are not included in this report.

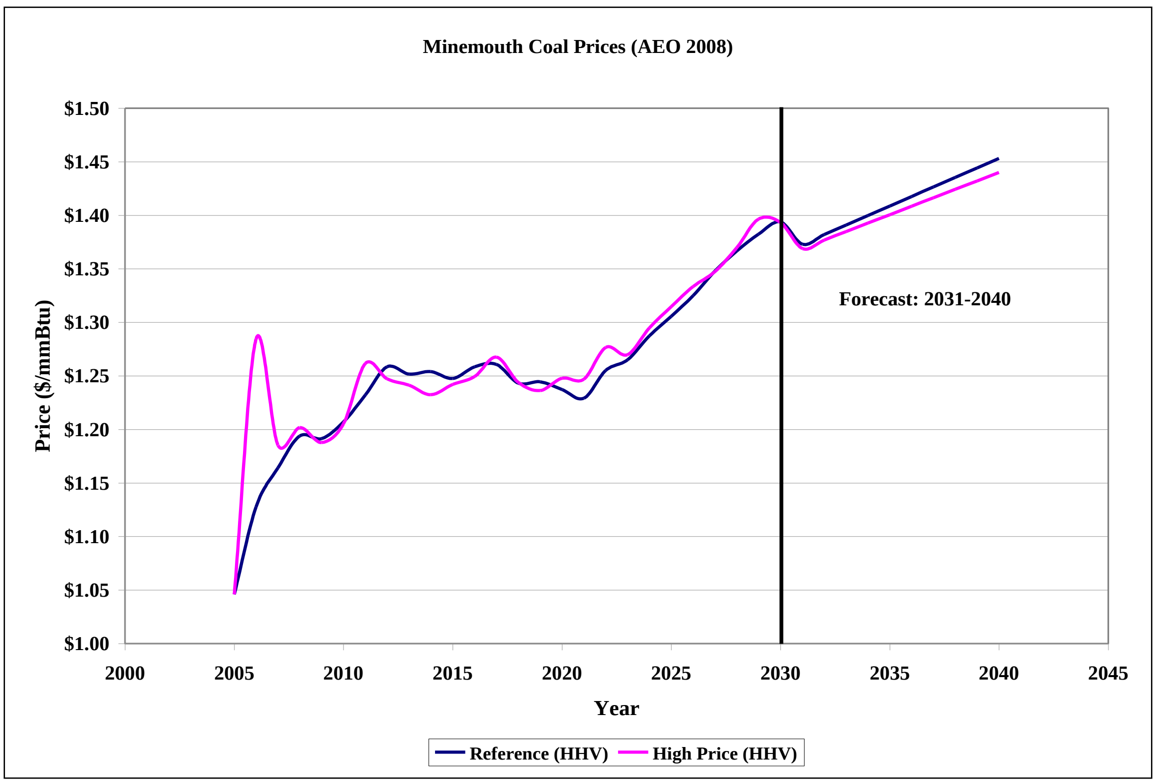

Figure 2-3: Minemouth Coal Prices for the Lifetime of the Plant, 2006-2040 (EIA, 2008)

2.1.2 Greenhouse Gas Emissions

Figure 2-4 and **Table 2-1** compare the GHG emissions for Stage #1 on a per kg coal produced basis (ready for transport). In this study the following definitions are used to describe the processes that occur during a stage:

- **Construction:** Emissions associated with the production of materials used during the construction of a process (i.e., steel used to build a power plant).
- **Commissioning/Decommissioning:** Commissioning is the energy used and emissions created while preparing the land to install the processing facility. This is also when land use change occurs. Decommissioning is energy use and emissions associated with removing the processing facility and returning the land to grassland.
- **Operations:** Energy use and subsequent emissions due to the operation of a process (electricity and diesel during coal mining, natural gas for the auxiliary boiler during power plant operations).

GHG emissions are calculated on both a mass (kg) and kg CO_2e basis to highlight the differences in impact when you consider the warming potential of a pollutant versus only the mass emitted. GWP values used to calculate the CO_2e listed in **Table 1-3**.

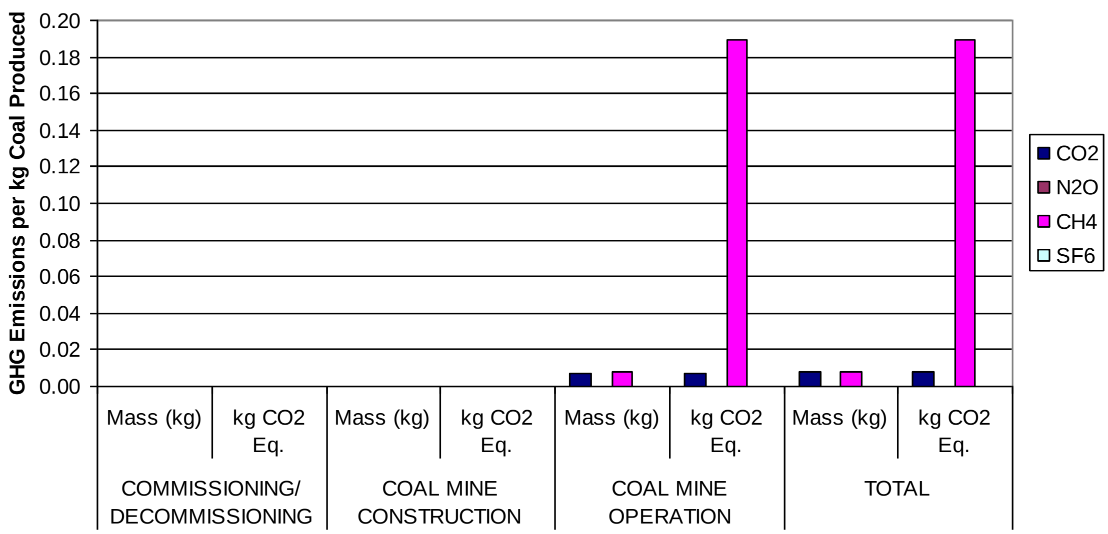

Figure 2-4: GHG Emissions/kg Coal Mine Output on a Mass and CO_2e Basis

GHG emissions in this stage are dominated by CH_4 emitted during coal mining operation; CH_4 gases are trapped in the coal bed and released when the coal is mined. On a mass basis, CH_4 and CO_2 have similar outputs, but because CH_4 has 25 times the GWP, the impact is larger. Emissions during commissioning/decommissioning and construction are small in comparison. The total GWP of Stage #1 is 0.20 kg CO_2e per kg coal ready for transport.

Table 2-1: GHG Emissions (on a Mass and CO_2e) /kg Coal Ready for Transport

Emissions (/kg coal)	Commissioning/ Decommissioning		Coal Mine Construction		Coal Mine Operation		Total	
	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	1.4E-05	1.4E-05	2.8E-04	2.8E-04	7.4E-03	7.4E-03	7.7E-03	7.7E-03
N_2O	2.5E-10	7.5E-08	1.2E-08	3.5E-06	1.1E-07	3.3E-05	1.2E-07	3.6E-05
CH_4	1.1E-08	2.7E-07	3.9E-07	9.8E-06	7.6E-03	1.9E-01	7.6E-03	1.9E-01
SF_6	3.8E-18	8.7E-14	1.3E-13	3.1E-09	4.5E-14	1.0E-09	1.8E-13	4.1E-09
Total GWP		1.4E-05		2.9E-04		2.0E-01		0.20

2.1.3 Air Pollutant Emissions

Table 2-2 and **Figure 2-5** summarize the air emissions (excluding GHGs) that are released during Stage #1 on a per kg of coal output (ready for transport) basis.

Table 2-2: Air Pollutant Emissions from Stage #1, kg/kg Coal Ready for Transport

Emissions	Commissioning/ Decommissioning	Coal Mine Construction	Coal Mine Operation	Total
Pb	4.51E-14	4.77E-10	3.29E-10	8.06E-10
Hg	4.21E-15	2.70E-11	9.18E-11	1.19E-10
NH_3	6.68E-12	7.36E-10	6.60E-08	6.68E-08
CO	3.45E-08	2.10E-06	7.29E-06	9.43E-06
NO_X	1.04E-07	5.22E-07	1.35E-05	1.41E-05
SO_X	4.09E-09	6.92E-07	3.74E-05	3.81E-05
VOC	4.56E-09	3.25E-08	2.39E-07	2.76E-07
PM	3.41E-07	9.84E-08	1.97E-06	2.41E-06

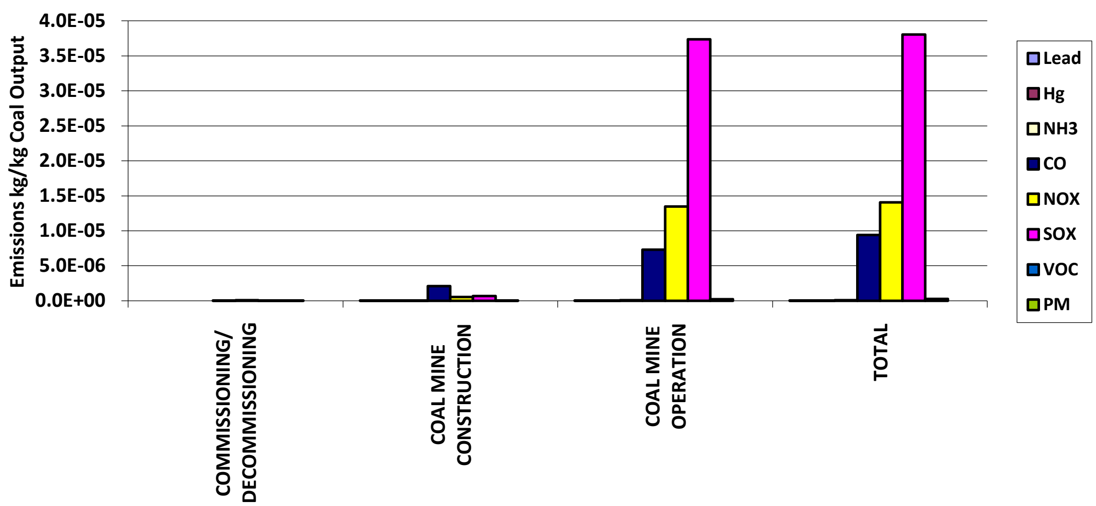

Figure 2-5: Air Pollutant Emissions from Stage #1, kg/kg Coal Ready for Transport

SO_X is the dominant emission during Stage #1, due mostly to LC emissions associated with electricity use. The carbon monoxide (CO) and NO_X emissions are due to combustion, and the PM emissions are due to fugitive dust during installation. However, all emissions at this stage are reported in very small quantities.

2.1.4 Water Withdrawal and Consumption

Table 2-3 shows water withdrawal and consumption, as well as wastewater outfall in Stage #1, on the basis of 1 kg coal ready for transport.

Table 2-3: Water Withdrawal and Consumption During Stage #1, kg/kg Coal Ready for Transport

Water (kg/kg Coal Output)	Commissioning/ Decommissioning	Coal Mine Construction	Coal Mine Operation	Total
Water Withdrawal	3.10E-06	1.39E-03	0.41	0.41
Wastewater Outfall	2.15E-06	1.80E-04	2.03	2.03
Water Consumption	9.50E-07	1.21E-03	-1.62	-1.62

All water withdrawal and consumption during commissioning/decommissioning and coalmine construction is attributed to secondary LCs such as diesel production and material manufacturing. The only primary data for water withdrawal and consumption during Stage #1 is for the coal mine operation, where water is used during coal prep cleaning and for dust suppression. Water output from the mine operations includes storm water and sanitary waste water as reported to the U.S. Environmental Protection Agency (EPA) by the Galatia Mine (EPA, 2008a). It is important to consider storm water from a coalmine in an LCI because it must be treated for sediment and other contaminants, and also requires energy during stormwater handling. However, no specific data were located on the water consumed during mine operations (such as water loss due to evaporation during coal cleaning), so a value could not be separated from the stormwater output. Therefore, a negative water consumed value (more output than input, or, water produced) is calculated for Stage #1.

2.2 Life Cycle Stage #2: Raw Material Transport

In Stage #2 it was assumed that the mined coal was transported by rail from the coal mine in southern Illinois to the energy conversions facility located in southwestern Mississippi, an assumed round trip distance of 1,170 miles. For this study, a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400-horsepower diesel engine (General Electric, 2008) and each car has a 91-tonne (100-ton) coal capacity (NETL, 2010).

The major operation included in this stage is the combustion of diesel by the locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. Emissions are due to diesel combustion and fugitive dust. It was assumed that the majority of the railway connecting the coalmine and the IGCC facility was existing infrastructure, which assuming this particular mine and facility did not exist, would still be operational. Therefore, only a rail spur from the coalmine and the facility to the main rail line was considered for land use change. No water withdrawal or consumption was assumed during Stage #2 operations.

2.2.1 LCC Data Assumption

The Baseline Report assumed an additional cost equal to 25 percent of the minemouth coal price (NETL, 2010) to account for transportation of the coal from the mine to the plant facility. Lacking other specific data on transportation costs, 25 percent was also assumed for this study. The result is the delivered coal price shown in **Figure 2-6**.

Because the coal is not used until gasification at the plant site, no cost modeling results are necessary for this stage. All cost model results are reported in the Stage #3 LCC results section.

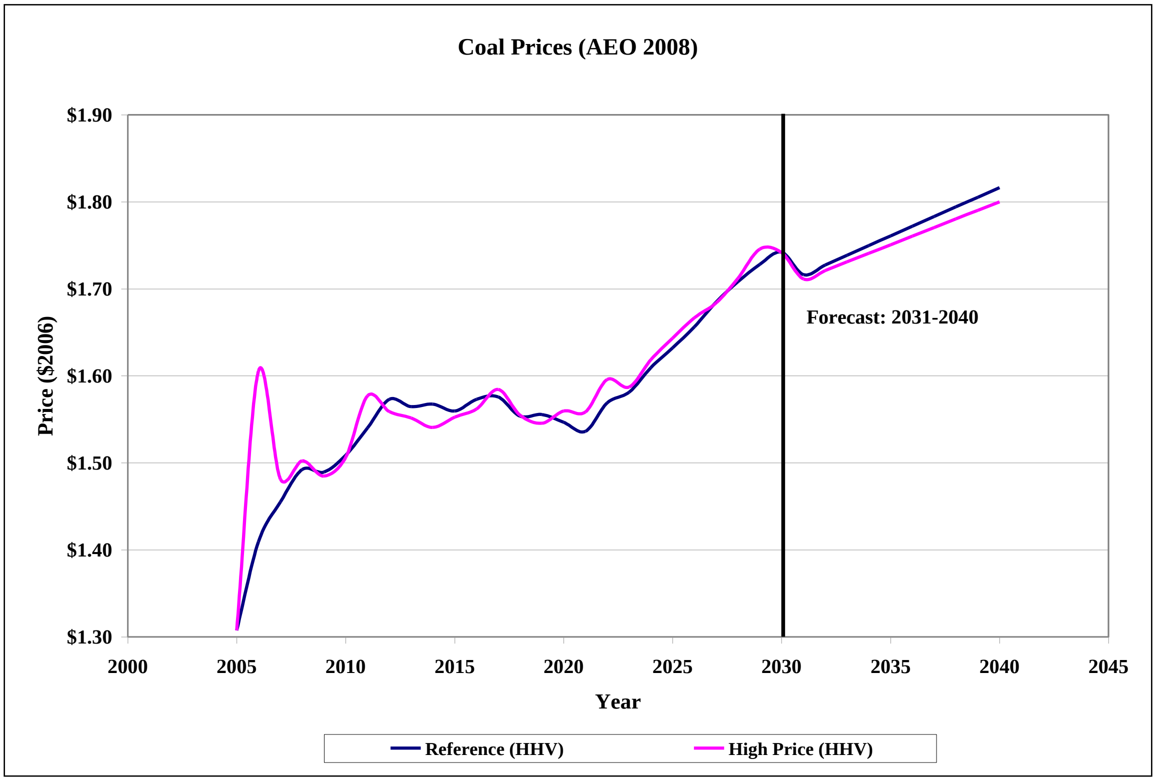

Figure 2-6: Delivered Coal Prices for Lifetime of the Plant

2.2.2 Greenhouse Gas Emissions

Table 2-4 and **Figure 2-7** show the GHG emissions for Stage #2 on a mass and CO_2e basis per kg of coal transported. CO_2 is the dominant pollutant due to the combustion of diesel fuel during train operation. Total GWP for Stage #2 is 0.037 kg CO_2e per kg of coal transported.

Table 2-4: Stage #2 GHG Emissions (Mass and CO_2e) /kg of Coal Transported

Processes	Train Construction		Transport Operation		Total	
Emissions (/kg coal)	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	9.1E-04	9.1E-04	3.5E-02	3.5E-02	3.6E-02	3.6E-02
N_2O	1.8E-08	5.4E-06	6.9E-08	2.1E-05	8.7E-08	2.6E-05
CH_4	1.4E-06	3.4E-05	4.4E-05	1.1E-03	4.6E-05	1.1E-03
SF_6	8.1E-14	1.8E-09	1.5E-14	3.5E-10	9.6E-14	2.2E-09
Total GWP		9.5E-04		3.6E-02		3.7E-02

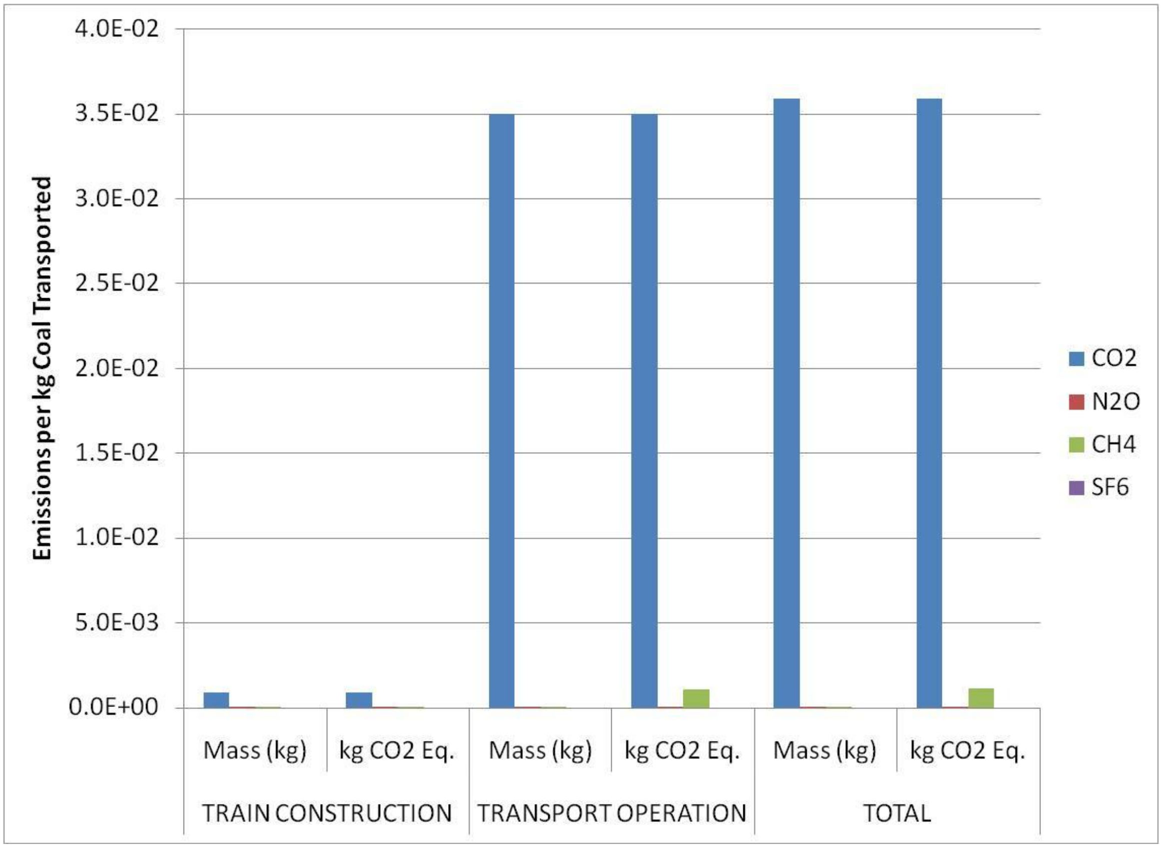

Figure 2-7: Stage #2 GHG Emissions (Mass and CO_2e) /kg of Coal Transported

2.2.3 Air Pollutant Emissions

Table 2-5 and **Figure 2-8** show the non-GHG air emissions associated with Stage #2 on a per kg coal transported basis. Emissions are dominated by the train operations, where diesel fuel is combusted to power the unit train.

Table 2-5: Stage #2 Air Emissions (kg/kg Coal Transported)

Emissions (kg/kg coal)	Train Construction	Transport Operation	Total
Pb	1.9E-10	6.2E-11	2.5E-10
Hg	1.3E-11	5.8E-12	1.9E-11
NH_3	1.9E-09	4.4E-07	4.5E-07
CO	4.9E-06	3.5E-05	3.9E-05
NO_X	1.0E-06	3.2E-05	3.4E-05
SO_X	3.0E-06	5.6E-06	8.7E-06
VOC	2.8E-08	3.0E-06	3.1E-06
PM	9.0E-07	4.0E-05	4.1E-05

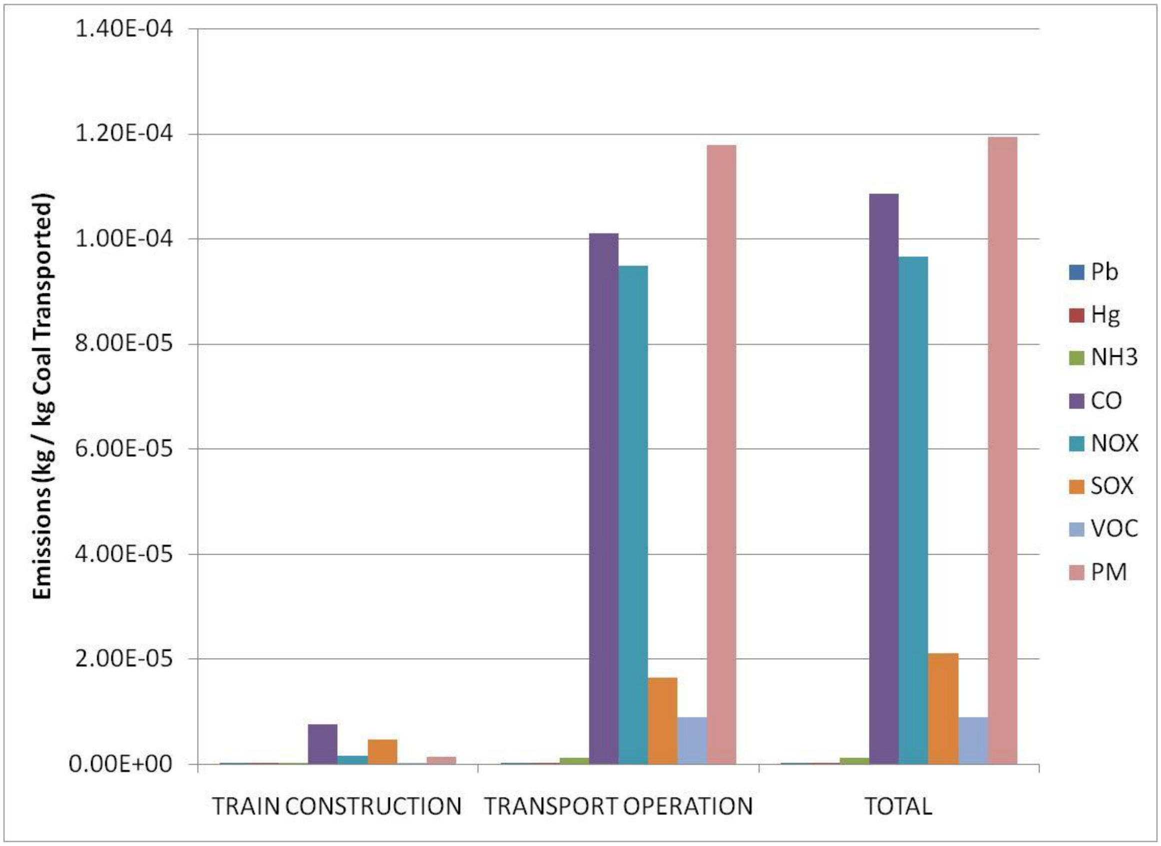

Figure 2-8: Stage #2 Air Emissions (kg/kg Coal Transported)

2.2.4 Water Withdrawal and Consumption

Water withdrawal and consumption for Stage #2 are shown in **Table 2-6**. No water withdrawal or consumption was associated with the primary processes of constructing and operating the train; however, water associated with secondary processes (the LC of diesel fuel and steel materials used during construction) does result in some water withdrawal/consumption. Therefore, the water and consumption for this stage are small and based solely on secondary data sources, such as GaBi profiles.

Table 2-6: Stage #2, Water Withdrawal and Consumption

Water (kg/kg Coal Output)	Train Construction	Transport Operation	Total
Water Withdrawal	6.21E-03	1.25E-02	1.87E-02
Wastewater Outfall	4.15E-03	8.70E-03	1.28E-02
Water Consumption	2.06E-03	3.84E-03	5.90E-03

2.3 Life Cycle Stage #3: Energy Conversion Facility for IGCC without CCS (Case 1)

The following briefly describes the operation of a 622-MWe net output IGCC plant without CCS; most data for this stage were taken from the Baseline Report (NETL, 2010). From the sparing philosophy employed in the Baseline Report, the plant design consists of the following major subsystems:

- Two air separation units (2 × 50 percent)
- Two trains of slurry preparation and slurry pumps (2 × 50 percent)
- Two trains of gasification, including gasifier, synthesis gas cooler, quench, and scrubber (2 × 50 percent)
- Two trains of syngas clean-up process (2 × 50 percent)
- Two trains of a single-stage Selexol® AGR (2 × 50 percent) and one Claus-based sulfur recovery unit (1 × 100 percent)
- Two CTG/HRSG tandems (2 × 50 percent)
- One STG (1 × 100 percent)

The number of trains is dependent on the equipment capacity; the 2 × 50 percent rating is to be interpreted as the number of train units and its capacity as a percentage of the total plant requirement.

The block flow diagram shown in **Figure 2-9** provides a simplified illustration of the interaction between major unit processes of the IGCC case without CCS (NETL, 2010). This figure shows only a single train for all IGCC subsystems and, as such, is not representative of the two trains used for several of the subsystems as described in the sparing philosophy.

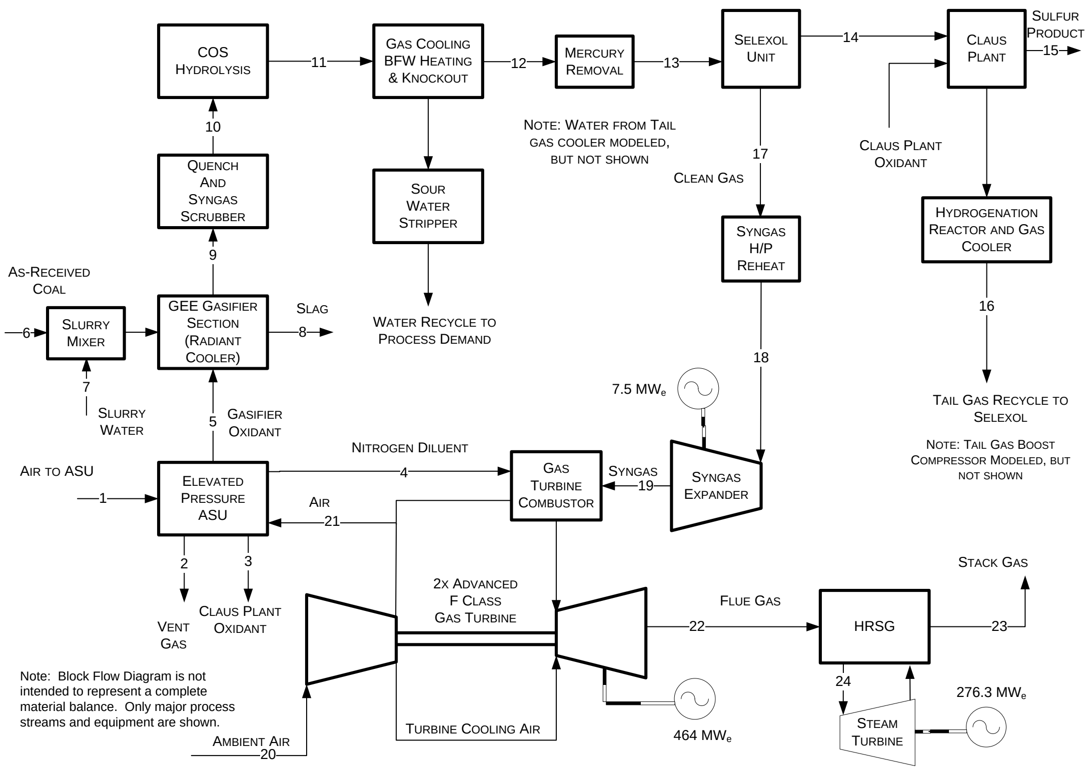

Figure 2-9: Process Flow Diagram, IGCC without CO_2 Capture (NETL, 2010)

Once the coal reaches the IGCC facility, it is unloaded from the rail cars via a trestle bottom dumper into two coal receiving hoppers. The coal is processed into a slurry and feed into the gasifier trains; which, when operating at maximum capacity, processes 5,083 tonnes per day (5,603 short tons per day). Oxygen (95 mole percent) from the air separation unit (ASU) is fed to the gasifier (Stream 5 as defined in **Figure 2-9**), which is used to gasify the coal into a syngas (Stream 8). The syngas continues through the system, being cooled, scrubbed, hydrolyzed, and cleaned before being expanded and combusted to create electricity via the F-class gas turbines. The flue gas is then sent through heat recovery and out of the stack. All emission control technologies were implemented pre-combustion during the syngas processing. In addition to the data provided in the Baseline Report, this study assumes that the electricity created by the turbine is processed by a switchyard and trunkline system before exiting the stage boundary. Therefore, the operation of that system is also included during Stage #3 of the IGCC plant. The reader is referred to the Baseline Report for more details on other streams shown in **Figure 2-9** (NETL, 2010).

Primary inputs associated with operation of the IGCC without CO_2 capture are the coal, air, natural gas for auxiliary boiler power, and process water. Because this stage contains the main operating process, the economic and environmental burdens of this stage are large compared to the preceding and subsequent LC stages.

2.3.1 LCC Data Assumption

Capital, material, and operating costs for both an IGCC power plant without CCS and an IGCC power plant with CCS were needed to calculate the total plant cost in both LC Costs and LCOE. **Table 2-7** lists the cost data and input parameters used to model the LCC for the IGCC plant without CCS. All values were reported in 2006 dollars and taken directly from the Baseline Report (NETL, 2010). It is assumed that replacement costs for the plant are included in the variable O&M costs taken from the Baseline Report. Fixed labor costs were not amended to account for the change in location of the IGCC plants; therefore, the labor costs listed in Table 4-13 still account for labor rates from the Midwest rather than Mississippi. Although this is recognized as a data limitation, the difference in rates was not assumed to make enough difference in results to warrant the complex recalculations necessary to account for the location change. Initial start-up costs are considered to be two percent of the total plant costs (capital investment) minus the costs for contingencies. This is included in the analysis as part of the capital investment costs.

Table 2-7: Cost Data from the NETL Baseline Report and Necessary LCC Input Parameters for IGCC without CCS (NETL, 2010)

Parameters	Values
Electricity Net (MW_e)	622
Capacity Factor	80%
Coal (Tons/day)	5,603
Initial Start-up Costs ($)[1]	$0
Capital Investment	$1,521,880,000
Fixed O&M Costs, Labor Cost ($/yr)[2]	$49,146,120
Variable O&M Cost ($/yr)[3]	$31,823,271

1. Initial start-up costs are wrapped into the capital investment.
2. Labor rates were not amended from the Baseline Report labor rates, despite re-location of the IGCC facilities from the Midwest to Mississippi.
3. Variable O&M costs exclude process water costs, and include replacement costs.

Coal, natural gas for the auxiliary boiler, and water were major inputs into the IGCC plant not considered in the capital or O&M costs assumed from the Baseline Report; all other inputs (catalyzes, solvents, etc.) were assumed to be included. Coal prices were assumed from AEO 2008 as defined in Stage #1 Cost Assumptions (**Section 2.1.1**). Natural gas costs for the auxiliary boiler were also determined using AEO 2008 values and were extended to 2040 based on AEO 2008 Reference case values (Table 3, Energy Prices by Sector and Source: Electric Power- Natural Gas). Due to the abrupt changes in the values from 2005 to 2030, the forecasted values for 2031 to 2040 assume the same trend as the values for 2022 through 2030, rather than assuming the trend of the entire set AEO values. A standard line equation was used, however, only the final eight years of the AEO forecasts were used. This is recognized as a simplification. **Figure 2-10** presents the AEO 2008 reference and high-case prices for natural gas based on HHV.

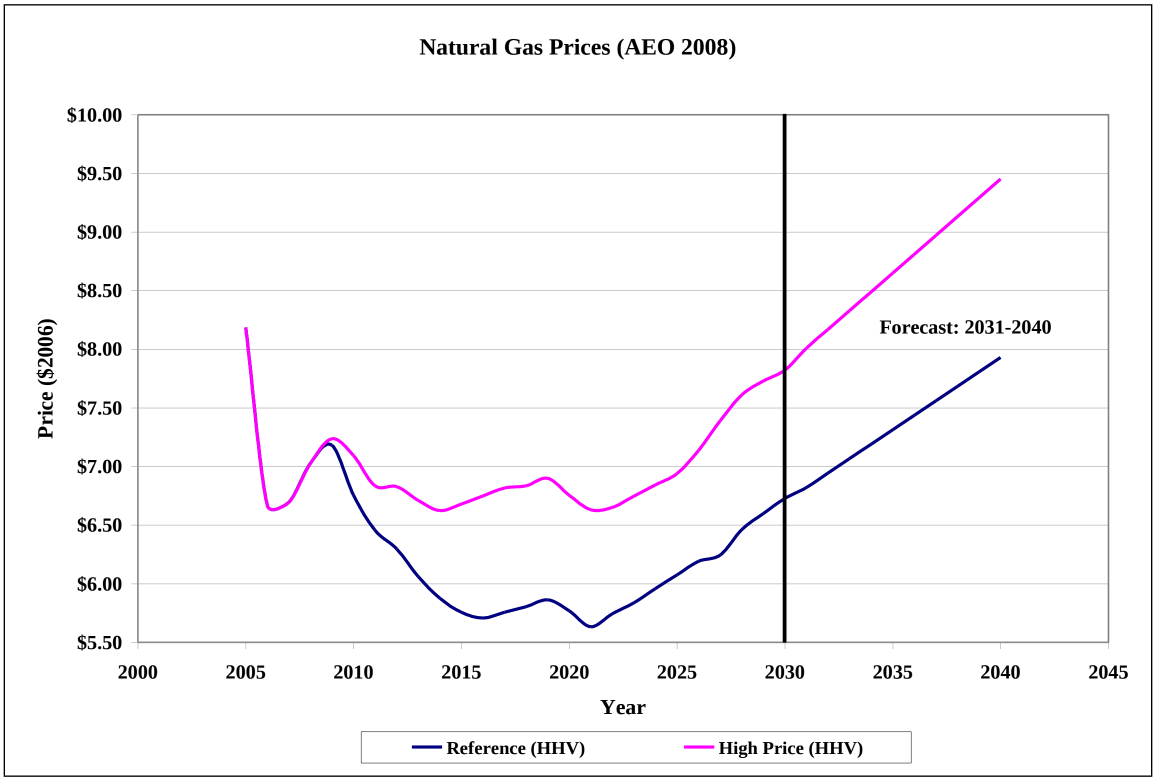

Figure 2-10: Natural Gas Prices for the Lifetime of the Plant

1. Prices ($/MMBtu) prior to 2030 calculated using AEO values (Reference Case/High Price Case Table 3 ($2006/MMBtu). Values post-2030 were extended using a regression based on the calculated values for price ($/MMBtu) 2005 through 2030.

Process water costs were estimated based on a Water and Wastewater Rate Survey Report (Rafaelis Financial Consulting, 2002). On a per liter basis, process water costs $0.00044. The total quantity of process water needed was taken from the Baseline Report. Because 50 percent of the water is purchased from the municipal supply, only 50 percent of the listed quantity was used to determine the cost of process water for these cases (NETL, 2010).

Table 2-8 defines the annual feedrate of each input. Annual feedrates for coal and process water were assumed from the Baseline Report. Natural gas was calculated based on an hourly federate (based on equipment specs) of 53,000 ft^3/hr (Wabash Power Equipment Company, 2009).

Table 2-8: Annual Feedrates for Feed/Fuel and Utilities for IGCC Case without CCS

Input	Annual Feedrate
Coal (Tons/day)	5,603
Natural Gas (mmBtu/day)[1]	131
Process Water (gallons/day)[2]	1,704,500

1. Natural gas consumed in the auxiliary boiler for start-up was calculated using a natural gas feed rate of 53,000 ft^3/hr and the assumption that the auxiliary boiler would be operating for 50 percent of the annual downtime (20 percent of the year).

2. Quantity listed accounts for the portion of water included in the costs of the plant, which excluded municipal water inputs.

2.3.1.1 Switchyard and Trunkline System

Included in the costs for Stage #3 are the capital costs for the switchyard and trunkline. Costs for the switchyard/trunkline system are not included in the Baseline Report, so additional sources of information were used. The switchyard system is composed of two components, circuit breakers and disconnect switches. Components in the trunkline are conductors and transmission towers.

There are four SF_6 gas circuit breakers and eight aluminum vertical break (AVB) disconnect switches used in the switchyard. Because no cost information could be found for a 345-kilovolt (kV) circuit breaker, the cost is for a breaker rated at 362 kV. The AVB disconnect switches are rated at 345 kV. Cost for the switchyard components are based on disclosed and non-disclosed manufacturer estimates. In total, the switchyard capital costs are approximately $1,040,101 (Zecchino, 2008).

The trunkline system is made up of 294 towers and three aluminum-clad steel reinforced conductors spanning 80 km (50 miles). The entire trunkline system equals $45,589,656 (ICF Consulting Ltd, 2002).

The cost for the total switchyard and trunkline system, including all four components in previously specified quantities, equals $46.6 million. All costs for the switchyard/trunkline system include only the cost of purchasing the component. Installation, labor, and additional material costs that may be necessary to install the system components are not included in the cost estimate. O&M costs are considered to be negligible and will not be included in the analysis. It is assumed that switchyard/trunkline life is the same as the 30-year plant life, therefore, no capital replacement costs are considered in the analysis. A seven percent transmission loss from the switchyard/trunkline system will be considered when calculating the LCOE for each case. **Table 2-9** gives a summary of the costs for the trunkline, switchyard, and total system.

Table 2-9: Switchyard/Trunkline Component Costs for IGCC Case 1, without CCS (Values in $2006) (Zecchino, 2008)

Component	Total Cost
Trunkline	$45,589,656.96
Switchyard	$1,040,100.70
Total System	$46,629,757.65

2.3.2 LCC Results

The LCOE for the IGCC without CCS is shown in **Figure 2-11**. The results indicate that capital costs account for the largest portion of the total LCC. Of the capital costs, the IGCC energy conversion facility contributes the majority of the cost at $0.0666 per kilowatt-hour (kWh), whereas the switchyard/trunkline system and decommissioning account for $0.0020/kWh and $0.0003/kWh, respectively. Decommissioning costs were not included in the Baseline Report, but 10 percent of the capital cost was attributed to decommissioning, a common assumption in the literature (Hill, O''Keefe *et al.*, 1995; Odeh and Cockerill, 2008; Gorokhov, Manfredo *et al.*, 2002). The decommissioning cost determination included the switchyard/trunkline and was only applied to capital costs; no data were available to make additional assumptions. Next to capital costs, the utility costs including coal feedstock, natural gas fuel, and process water contribute the second largest amount to the total LCC, or $0.0220/kWh. Variable O&M and labor costs contribute $0.0100/kWh and $0.0173/kWh. The total LC LCOE for the IGCC case without CCS is equal to $0.1194/kWh.

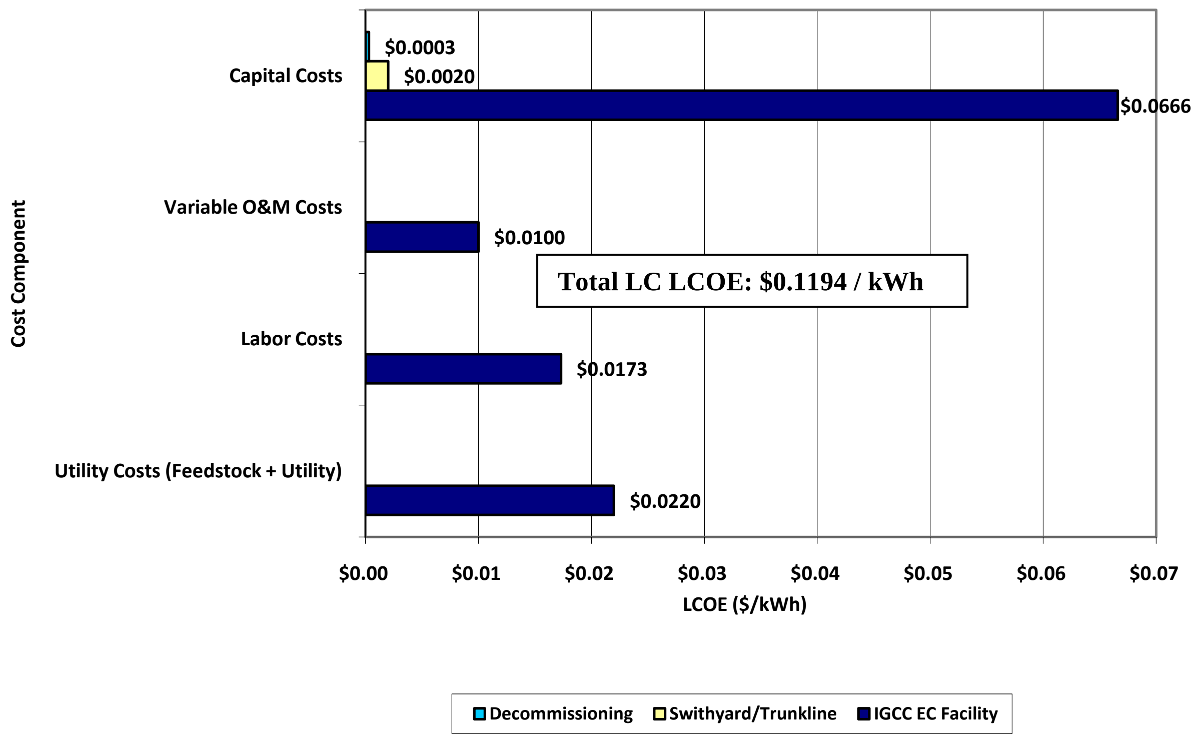

Figure 2-11: LCOE Results for IGCC Case without CCS

1. All calculations are based on an 80 percent capacity factor and include a seven percent electricity loss during transmission.

2.3.3 Greenhouse Gas Emissions

Table 2-10 and **Figure 2-12** show the GHG emissions associated with the IGCC without CCS plant, on an MWh plant output basis. CO_2 is the dominant pollutant, with the largest emissions associated with the gasification of coal. The total GWP of this stage is 905.32 kg CO_2e per MWh plant output.

Table 2-10: Stage #3 Case 1, GHG Emissions on an MWh Plant Output Basis

Emissions (kg / MWh)	Plant Construction		Plant Operation		Installation/ Deinstallation		Total	
	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	0.77	0.77	904.47	904.47	0.05	0.05	905.29	905.29
N_2O	1.76E-05	5.23E-03	4.32E-06	1.29E-03	1.21E-06	3.59E-04	2.31E-05	6.88E-03
CH_4	5.83E-04	1.46E-02	8.94E-04	2.24E-02	6.13E-05	1.53E-03	1.54E-03	3.85E-02
SF_6	9.96E-12	2.27E-07	3.32E-07	7.57E-03	2.16E-14	4.91E-10	3.32E-07	7.57E-03
Total GWP		0.79		904.50		0.05		905.35

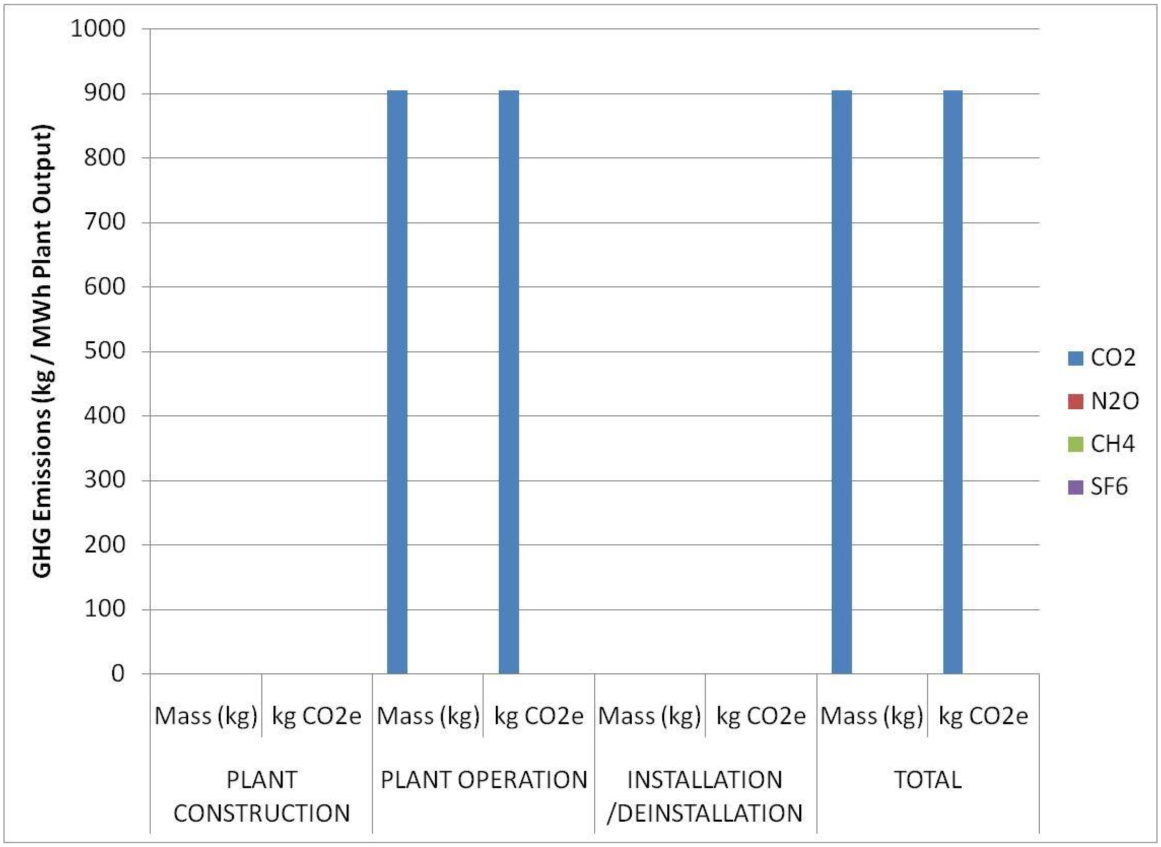

Figure 2-12: Stage #3 Case 1, GHG Emissions on an MWh Plant Output Basis

2.3.4 Air Pollutant Emissions

Table 2-11 and **Figure 2-13** show the air pollutants released during IGCC plant operations on a per MWh output basis. As with GHGs, emissions are dominated by the gasification of coal during plant operation. These emissions reflect the use of best practice emissions control technologies for SO_X, NO_X, PM, and Hg as outlined in the Baseline Report (NETL, 2010).

Table 2-11: Stage #3 Case 1, Air Pollutants (kg/MWh Plant Output)

Emissions (kg / MWh)	Plant Construction	Plant Operation	Installation/ Deinstallation	Total
Pb	5.3E-07	1.3E-05	2.6E-10	1.4E-05
Hg	3.3E-08	2.5E-06	2.4E-11	2.6E-06
NH_3	1.5E-06	2.4E-07	1.8E-06	3.6E-06
CO	3.0E-03	4.8E-04	2.0E-03	5.5E-03
NO_X	1.6E-03	2.7E-01	7.4E-04	2.7E-01
SO_X	2.8E-03	6.2E-03	4.1E-05	9.0E-03
VOC	6.1E-05	2.5E-05	1.9E-04	2.8E-04
PM	8.3E-04	3.3E-02	9.8E-05	3.4E-02

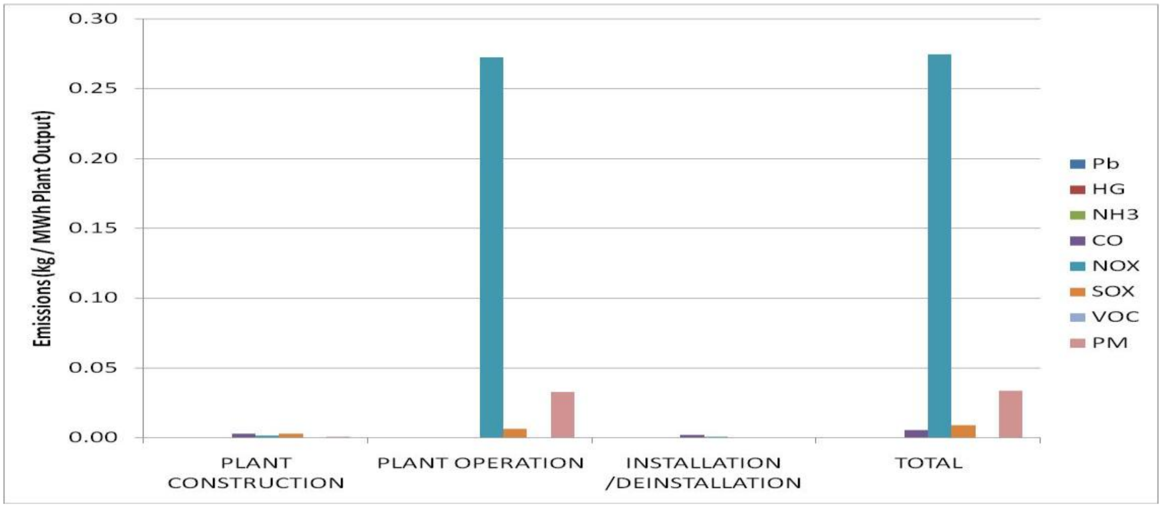

Figure 2-13: Stage #3 Case 1, Air Pollutants (kg/MWh Plant Output)

2.3.5 Water Withdrawal and Consumption

Table 2-12 shows water withdrawal and consumption for the IGCC plant without CCS. The most water is consumed during plant operation due to cooling water evaporation. A small amount of water withdrawal/consumption during plant construction is due to dust suppression.

Table 2-12: Stage #3, Case 1 Water Withdrawal and Consumption (kg/MWh Plant Output)

Water (kg/MWh)	Plant Construction	Plant Operation	Installation/ Deinstallation	Total
Water Withdrawal	4.38	1996.72	0.14	2001.23
Wastewater Outfall	2.15	412.92	0.01	415.08
Water Consumption	2.23	1583.80	0.12	1586.15

2.4 Life Cycle Stage #3: Energy Conversion Facility for IGCC with CCS (Case 2)

The following briefly describes the operation of a 556-MWe net output IGCC plant with CCS; as with the operation of the IGCC plant without CCS (**Section 2.3**) most data were taken directly from the Baseline Report. From the sparing philosophy employed in the Baseline Report, the plant design consists of the following major subsystems:

- Two air separation units (2 × 50 percent)
- Two trains of slurry preparation and slurry pumps (2 × 50 percent)
- Two trains of gasification, including gasifier, synthesis gas cooler, quench, and scrubber (2 × 50 percent)
- Two trains of syngas clean-up process (2 × 50 percent)

- Two trains of a two-stage Selexol® AGR (2 × 50 percent) and one Claus-based sulfur recovery unit (1 × 100 percent)
- Two CTG/HRSG tandems (2 × 50 percent)
- One STG (1 × 100 percent)

Figure 2-14 contains many of the same operation steps and processes that were shown previously in **Figure 2-9:** Process Flow Diagram, IGCC without CO2 Capture. The only difference between the cases is that the AGR process in this case is operated as a dual stage Selexol® capture process designed to selectively separate hydrogen sulfide (H_2S) and CO_2 in two streams. The concentrated H_2S gas stream is then conveyed to a Claus plant where the concentrated CO_2 stream is then routed to the CO_2 compression stage. In the CO_2 compression stage, CO_2 is dehydrated and compressed to a pressure of 15.3 megapascals (MPa) (2,215 psia) – appropriate for pipeline transport and direct injection/saline sequestration.

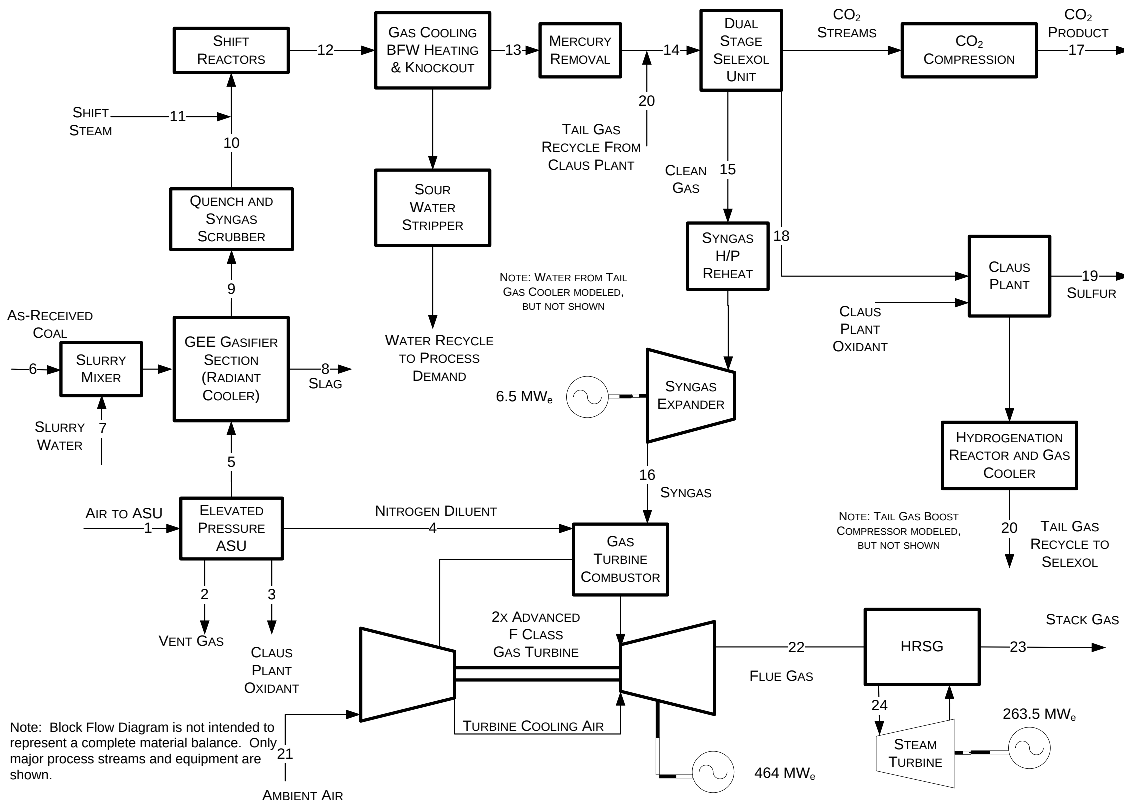

Figure 2-14: Process Flow Diagram, IGCC with CO_2 Capture (NETL, 2010)

Adding CCS to the IGCC plant decreases the net power output, increases water and reagent requirements, and slightly increases byproduct production rates, while achieving approximately 90 percent carbon capture from the syngas. Stage #3 for the IGCC case with CCS also includes consideration of the natural gas used in the auxiliary boiler and the switchyard and trunkline operations. The reader is referred to the Baseline Report for more details on other streams shown in **Figure 2-14** (NETL, 2010).

2.4.1 LCC Data Assumption

Assumptions for the IGCC case Stage #1 and Stage #2, as well as the assumptions for costs for LC Stage #3, are described within the previous sections relating to Stage #1 and Stage #2 and the IGCC facility without CCS. **Table 2-13** lists the assumptions and parameters used to determine the IGCC with CCS cost analysis results. The IGCC plant with CCS has a net electricity output of 556 MW at a capacity of 80 percent (NETL, 2010).

Table 2-13: IGCC Facility with CCS Cost Parameters and Assumption Summary

Parameter	IGCC w/ CCS
Electricity Net (MWe)	543.25
Capacity Factor	80%
Initial Costs ($)[1]	$0
Capital Investment	$1,811,411,000
Fixed O&M Costs, Labor Cost ($/yr)[2]	$56,432,165
Variable O&M Cost ($/yr)[3]	$35,519,462

1. Initial start-up costs are wrapped into the capital investment.Labor rates were not amended from the Baseline Report labor rates, despite re-location of the IGCC facilities from the Midwest to Mississippi.
2. Variable O&M costs exclude process water costs, and include replacement costs.

The same assumptions apply to the IGCC case with CCS as applied to the feed/fuel and utilities used for the IGCC case without CCS (**Section 2.3.1**). The feed quantities of natural gas and process water are listed again in **Table 2-14** for completeness. IGCC with CCS requires 129 additional tons/day of coal input to account for increased auxiliary load.

Table 2-14: Annual Feedrate for Feed/Fuel and Utilities for IGCC Case with CCS

Input	Annual Feedrate
Coal (Tons/day)	5,844
Natural Gas (mmBtu/day)[1]	131
Process Water (gallons/day)[2]	2,093,500

1. Natural gas consumed in the auxiliary boiler for start-up was calculated using a natural gas feed rate of 53,000 ft^3/hr and the assumption that the auxiliary boiler would be operating for 50 percent of the annual downtime (20 percent of the year).
2. Quantity listed accounts for the portion of water included in the costs of the plant, which excludes municipal water inputs.

CO_2 Transportation, Sequestration and Monitoring

For the IGCC case with CCS, CO_2 transportation, sequestration, and monitoring (TS&M) costs are included in the Stage #3 costs. Contributing to the TS&M costs are the capital and O&M costs for the CO_2 pipeline, injection wells, and O&M costs for the monitoring of the sequestration site.

CO_2 Pipeline

Based on the diameter, 43.17 centimeters (cm) (17 inches), and length, 160 km (100 miles), of the CO_2 pipeline, the capital costs and fixed O&M costs were calculated. The following equations were used to calculate the material, land, labor, and miscellaneous costs in dollars per mile ($/mile) included in the capital investment costs (Argonne National Laboratory, 2008):

$$Material(\$/mile) = 1.1(330.5d^2 + 687d + 26{,}960)$$
$$Land(\$/mile) = 1.1(577d + 29{,}788)$$
$$Labor(\$/mile) = 1.1(343d^2 + 2074d + 170{,}013)$$
$$Misc(\$/mile) = 1.1(8417d + 7324)$$

Where: "d" equals the diameter of the pipeline, measured in inches. The costs ($/mile) calculated using the equations listed above were added together to give the capital cost per mile and then multiplied by the number of pipelines, one in this case, and the length of the pipeline (miles). This translates to a capital investment cost for the 160.9 km (100 miles) of CO_2 pipeline equal to $69,104,365. The fixed O&M costs were determined using the following assumptions:

1. There is one full-time laborer per 160.9 km (100 miles) of pipeline being paid $15.05 per hour for 2,080 hours per year.
2. General and administrative (G&A) labor is considered to be equal to 50 percent of the labor costs (one full-time laborer per 160.9 km [100 miles]).
3. Other O&M costs are equal to four percent of the total annual capital investment.

Total fixed O&M costs were calculated by adding G&A labor and other O&M costs together. These costs totaled $2,779,827. Labor is considered a stand-alone fixed cost and equals $31,304. **Table 2-15** summarizes the CO_2 pipeline capital and O&M costs.

Table 2-15: Summary of CO_2 Pipeline Capital and Fixed Costs

CO_2 Pipeline	IGCC w/CCS
Material Cost ($/mile)	$147,568.85
Labor Cost ($/mile)	$334,837.80
Misc Costs ($/mile)	$165,454.30
Land Costs ($/mile)	$43,182.70
Total CO_2 Pipeline Capital Costs ($/100 miles)	$69,104,365.00
Labor (Annual)	$31,304.00
G&A Labor (Annual)	$15,652.00
Other O&M Costs (Annual)	$2,764,175
Total O&M Costs (Annual)	$2,779,826.60
Total length of pipeline (miles)	100

CO_2 Sequestration

Both construction and operation economic costs will be modeled for CO_2 injection and sequestration into a geologic saline formation. Costs related to the CO_2 injection well were determined based on the LCOE calculation spreadsheet model used for the Baseline. For the IGCC case with CCS, it is assumed that two, 1,239 meter (4,065 ft) wells will be used to store CO_2. This well will be injected daily with 9,063 tonnes (10,318 tons) of CO_2. According to this model, total capital costs for the project equals $7.7 million. Capital costs include the siting, well construction, installation of equipment, and other miscellaneous costs including project and process contingency costs. Fixed operating costs, including normal daily expenses and maintenance on the surface and subsurface, have a total cost of $202,000 per year. The variable operating costs equal $37,000 per year.

Monitoring costs are not included in the injection well costs; rather, these costs will be determined based on the amount of CO_2 sequestered per year and the monitoring costs found within the Baseline Report, $0.176. There are no capital costs included in the monitoring costs, only O&M costs.

2.4.2 LCC Data Results

Figure 2-15 presents the LC LCOE results for the IGCC case with CCS. As with the case without CCS, the IGCC energy conversion facility accounts for the majority of the costs for the case LC. The capital costs contribute the majority of the costs when analyzed by cost component. Of the capital costs, the IGCC energy conversion facility is equal to $0.0907/kWh, whereas the switchyard/trunkline and decommissioning of the system contribute $0.0023/kWh and $0.0005/kWh to the LC capital costs. Decommissioning costs were not included in the Baseline Report, but 10 percent of the capital cost was attributed to decommissioning, a common assumption in the literature (Hill, O"Keefe *et al.*, 1995; Odeh and Cockerill, 2008; Gorokhov, Manfredo *et al.*, 2002). The decommissioning cost determination included the switchyard/trunkline and carbon capture system, and was only applied to capital costs; no data were available to make additional assumptions. Utility costs including coal feedstock, natural gas fuel for the auxiliary boiler, and process water accounts for $0.0263/kWh, followed by contributions of $0.0143/kWh and $0.0227/kWh from variable O&M and labor costs.

The CO_2 TS&M costs include capital and O&M costs for the CO_2 pipeline and injection wells, as well as the O&M costs for monitoring. In the IGCC case with CCS, the CO_2 TS&M has an LCOE of $0.0052/kWh, which is split between capital, O&M, and labor costs. Capital costs for the CO_2 TS&M are equal to $0.0041/kWh, whereas labor and variable O&M are equal to $0.0001/kWh and $0.0011/kWh. The capital costs for the CO_2 capture equipment are included in the IGCC energy conversion facility cost, as calculated in the Baseline Report. The total LC LCOE for the IGCC case with CCS is equal to $0.1621/kWh.

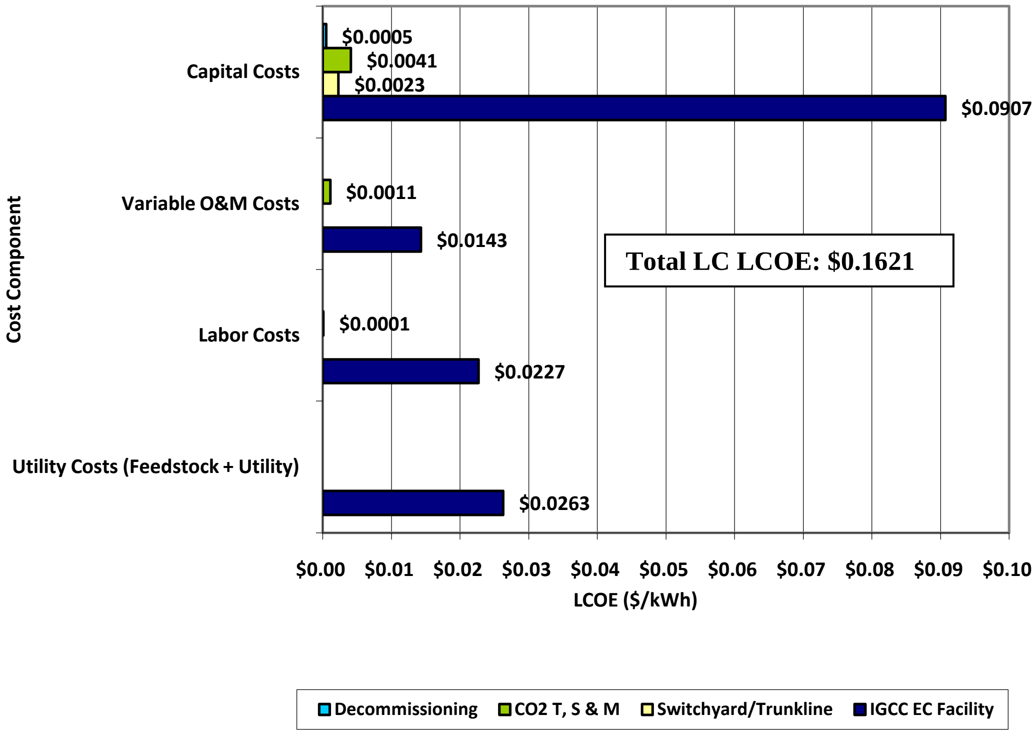

Figure 2-15: LCOE for IGCC Case with CCS

1. IGCC EC facility represents the energy conversion facility alone.
1. CO_2 TS&M represents the transportation, sequestration, and monitoring of the CO_2.
2. The labor cost for CO_2 TS&M are small and therefore are not represented on the chart with a bar; only the value of $0.00001/kWh appears on the chart.
3. All calculations are based on an 80 percent capacity factor and include a seven percent electricity loss during transmission.

TPC (total plant cost) includes the cost of equipment, materials, labor, engineering and construction management, and contingencies related to the construction of a facility. It does not include owner's costs, such as the acquisition of land, licenses, or administrative costs. In this study the capital costs include those of the energy conversion facility, switchyard and trunkline, and decommissioning activities. In the cases for CCS, the capital costs also include the CO_2 pipeline and injection well. The TPC for the IGCC facilities are normalized to the basis of net power output, which is 622 MW for the IGCC facility and 543 MW for the IGCC facility with CCS. (Net power output does not account for the capacity factor of the energy conversion facility or the transmission loss of electricity.) The TPC of the base IGCC facility is $2,774/kW; 88 percent of this TPC is related to the energy conversion facility, and the balance is related to the switchyard and trunkline and decommissioning activities. The TPC of the IGCC facility with CCS is $3,918/kW, which 41 percent higher than the base IGCC facility. For the IGCC facility with CCS, 85 percent of the TPC is related to the energy conversion facility, 3 percent is related to the CO_2 pipeline and injection well, and the balance is related to the switchyard and trunkline and decommissioning activities. The TPC of the IGCC facilities are presented in **Figure 2-16**.

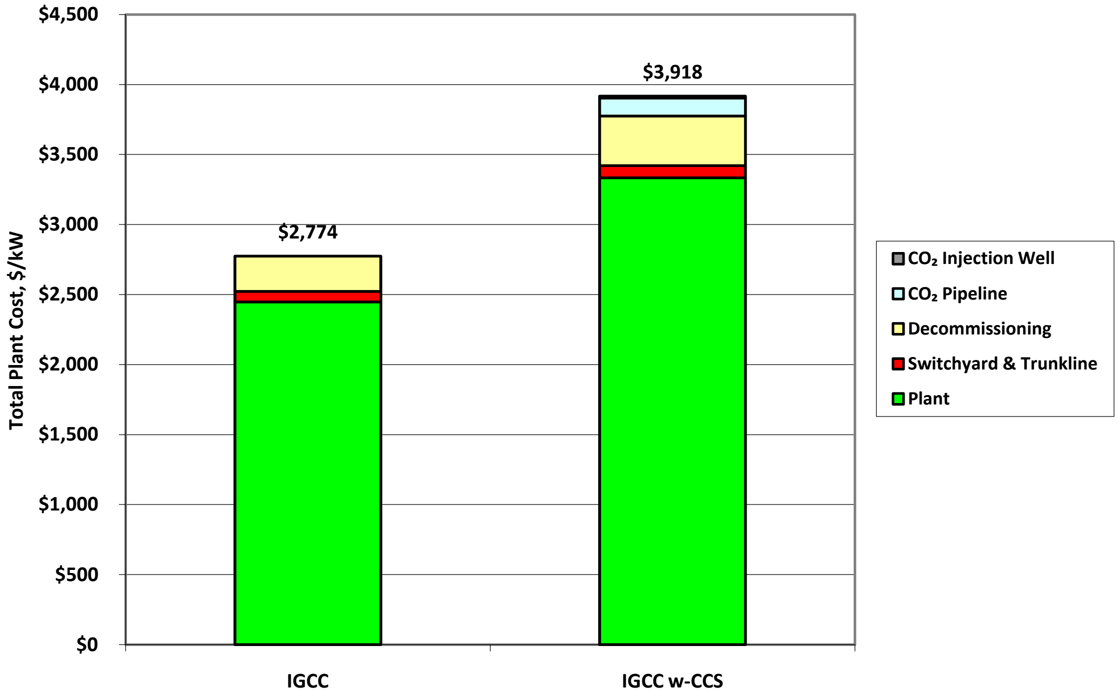

Figure 2-16: TPC ($/kW) for IGCC Cases

2.4.3 Greenhouse Gas Emissions

Table 2-16 and **Figure 2-17** show the GHG emissions associated with the IGCC with CCS plant, on an MWh plant output basis. CO_2 is still the dominant GHG pollutant, with the largest emissions associated with the gasification of coal. However, the addition of CCS reduces the magnitude of emissions by a nominal 90 percent (NETL, 2010). An additional phase and pipeline installation/deinstallation is included in Case 2, and a very small amount (less than one percent of the total) of additional GHG emissions are associated with that process.

Table 2-16: Stage #3 Case 2, GHG Emissions/MWh Plant Output

Emissions/ MWh	Plant Construction		Installation/ Deinstallation (I/D)		Plant Operation		CO_2 Pipeline I/D		Total	
	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	1.17	1.17	0.06	0.06	118.52	118.52	0.04	0.04	119.79	119.79
N_2O	3.8E-05	1.1E-02	1.4E-06	4.3E-04	4.9E-06	1.5E-03	7.6E-07	2.3E-04	4.5E-05	1.3E-02
CH_4	9.7E-04	2.4E-02	7.3E-05	1.8E-03	1.0E-03	2.6E-02	3.9E-05	9.7E-04	2.1E-03	5.3E-02
SF_6	9.5E-12	2.2E-07	2.5E-14	5.8E-10	3.8E-07	8.7E-03	1.4E-14	3.1E-10	3.8E-07	8.7E-03
Total GWP		1.20		0.06		118.56		0.04		119.86

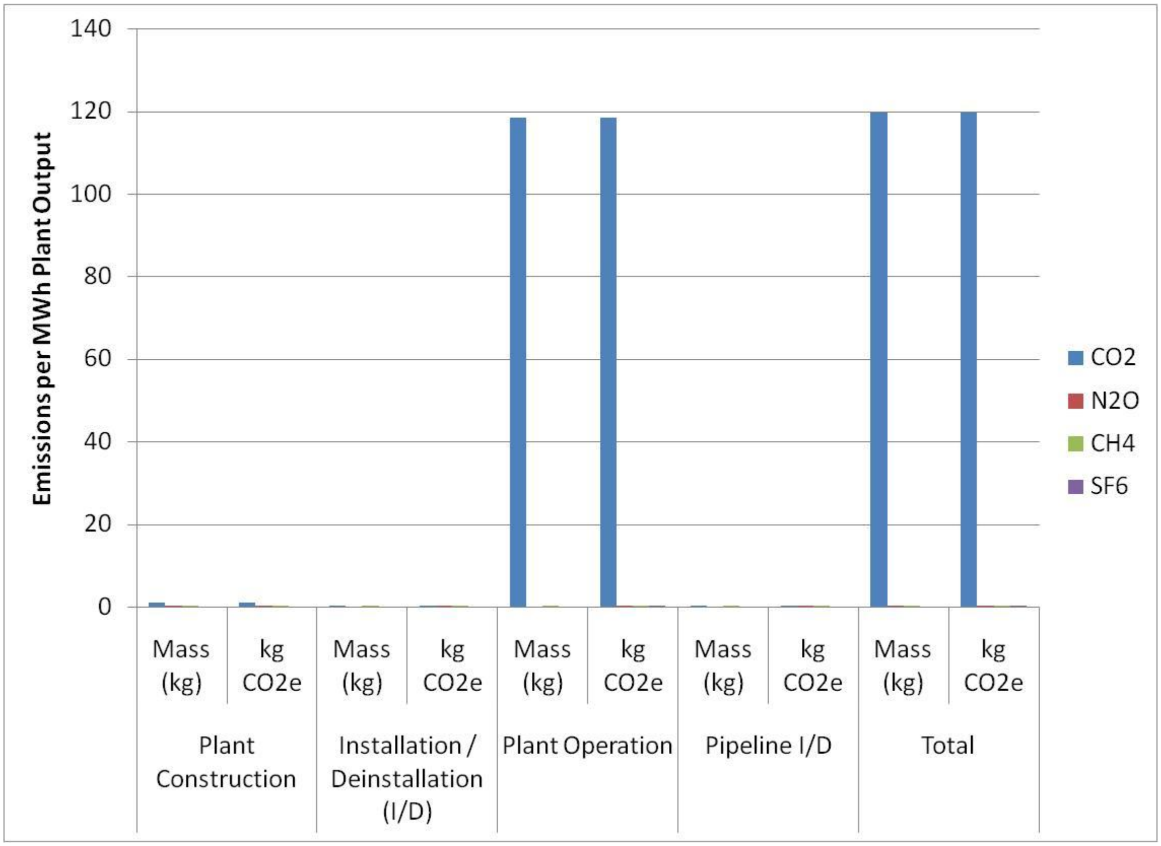

Figure 2-17: Stage #3 IGCC Case 2, GHG Emissions/MWh Plant Output

2.4.4 Air Pollutant Emissions

Table 2-17 and **Figure 2-18** show the air pollutants released during IGCC plant operations on a per MWh output basis. As with GHGs, emissions are dominated by the gasification of coal during plant operation. These emission values reflect the use of best practice emissions control technologies for SO_X, NO_X, PM, and Hg as outlined in the Baseline Report (NETL, 2010). Less than one percent of air emissions are associated with pipeline installation/deinstallation.

Table 2-17: Stage #3 Case 2, Air Emissions (kg/ MWh Plant Output)

Emissions (kg/ MWh)	Plant Construction	Plant Operation	Pipeline I/D	Plant I/D	Total
Pb	1.52E-06	1.60E-05	1.62E-10	3.03E-10	1.75E-05
Hg	7.03E-08	2.90E-06	1.51E-11	2.82E-11	2.97E-06
NH_3	1.57E-06	2.73E-07	1.15E-06	2.15E-06	5.14E-06
CO	5.98E-03	5.48E-04	1.28E-04	2.39E-03	9.05E-03
NO_X	2.30E-03	2.67E-01	3.67E-04	8.76E-04	2.71E-01
SO_X	3.96E-03	1.19E-02	1.44E-05	4.85E-05	1.60E-02
VOC	1.14E-04	2.88E-05	2.61E-05	2.27E-04	3.96E-04
PM	1.16E-03	3.87E-02	7.06E-05	1.16E-04	4.00E-02

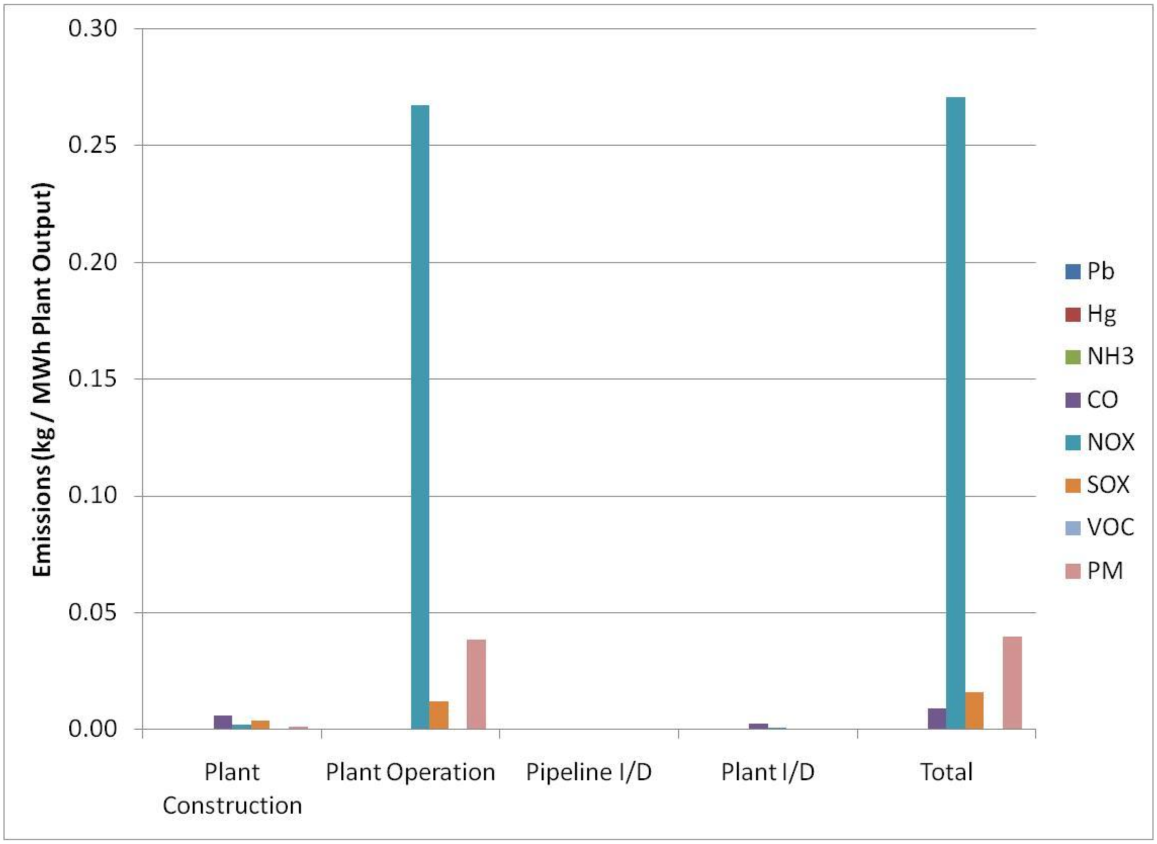

Figure 2-18: Stage #3 Case 2, Air Emissions (kg/ MWh Plant Output)

2.4.5 Water Withdrawal and Consumption

Table 2-12 shows water withdrawal and consumption for the IGCC plant with CCS. As with Case 1 (without CCS), the most water is consumed during plant operation due to cooling water evaporation, which accounts for 81 percent of the makeup requirements (NETL, 2010). The small amount of water withdrawal/consumption during plant construction is due to dust suppression.

Table 2-18: Stage #3 Case 2, Water Withdrawal and Consumption (kg/MWh Plant Output)

Water (kg/MWh)	Plant Construction	Plant Operation	Pipeline I/D	Installation/ Deinstallation	Total
Water Withdrawal	7.95	2809.91	0.01	0.16	2818.03
Wastewater Outfall	2.32	523.90	0.01	0.01	526.24
Water Consumption	5.63	2286.01	0.00	0.15	2291.79

2.5 Life Cycle Stages #4 & 5: Product Transport and End Use

Once the electricity is produced and sent through the switchyard and trunkline system it is ready for transmission, via the grid, to the user. A seven percent loss in electricity during transmissions was assumed for all the NETL power LCI&C studies (Bergerson, 2005; EIA, 2007b). Seven percent was calculated with a standard deviation of ±0.5 percent, which when checked for sensitivity resulted in a ±0.53 percent change in all LCI outputs. Therefore sensitivity impacts on transmission loss were considered insignificant. This loss only impacts the cost parameters, as no environmental inventories are associated with transmission loss. The transmission line was considered existing infrastructure, therefore, the construction of the line, along with the associated costs, emissions, and land use changes, was not included within the system boundaries for this study.

However, SF_6 leakage does occur due to circuit breakers used through the U.S. transmission line system and was therefore included in the Stage #4 inventory. An average leakage rate of 1.4×10^{-4} kg SF_6/MWh was calculated based on 2007 leakage rates reported by the EPA's SF_6 Emission Reduction Partnership (EPA, 2007). Additional consideration was given to leakage by companies outside the partnership to calculate the assumed leakage rate. SF_6 leakage during Stage #4 was calculated at 1.4×10^{-4} kg/MWh (plant output minus transmission loss). The total GWP of Stage # 4 is 3.3 kg CO_2 equivalents per MWh delivered energy.

As with Stage #1 and Stage #2, costs associated with transmission losses are included with the LC Stage #3 results. Costs are based on an electricity output that considers both the 80 percent capacity factor of both IGCC plants and the seven percent loss during transmission.

Finally, in LC Stage #5, the electricity is delivered to the end user. All NETL power generation LCI&C studies assume electricity is used by a non-specific, 100 percent efficient process. This assumption avoids the need to define a unique user profile and allows all power generation studies to be compared on equal footing. Therefore, no environmental inventories or cost parameters were collected for Stage #5.

3.0 Interpretation of Results

The following sections report comparative assessment results over the complete LC for both cases considering GWP impact, LCC results, and quantification of total outputs for all other LCI metrics. In addition, this section will report the results of sensitivity analysis.

3.1 LCI results: IGCC without CCS

Table 3-1 summarizes all water withdrawals, consumptions, and emissions from the IGCC without CCS case, in kg/MWh, for each stage and the total LC. No environmental impacts are associated with Stage #5. Similarly, only GHG emissions associated with SF_6 leakage are included in Stage #4. Therefore, Stage #5 will not be discussed further, and Stage #4 will only be included when discussing GHG emissions.

Table 3-1: Water and Emissions Summary for Case 1, IGCC without CCS

Parameters	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: IGCC without CCS	Stage #4: Transmission & Distribution	Stage #5: End User	Total
GHG Emissions kg/MWh						
CO_2	2.83	13.14	841.92	0	0	857.90
N_2O	4.4E-05	3.19E-05	2.1E-05	0	0	9.8E-05
CH_4	2.77	0.02	0.00	0	0	2.79
SF_6	6.5E-11	3.52E-11	3.1E-07	1.4E-04	0	1.4E-04
Air Pollutants (non GHG) kg/MWh						
Pb	2.9E-07	1.7E-07	1.3E-05	0	0	1.3E-05
Hg	4.3E-08	1.4E-08	2.4E-06	0	0	2.4E-06
NH_3	2.4E-05	4.8E-04	3.3E-06	0	0	5.0E-04
CO	3.5E-03	4.0E-02	5.1E-03	0	0	4.8E-02
NO_X	5.2E-03	3.5E-02	2.6E-01	0	0	3.0E-01
SO_X	1.4E-02	7.8E-03	8.4E-03	0	0	3.0E-02
VOC	1.0E-04	3.3E-03	2.6E-04	0	0	3.6E-03
PM	8.8E-04	4.4E-02	3.1E-02	0	0	7.6E-02
Water Withdrawal and Consumption kg/MWh						
Input_Ground	128.40	0.66	929.92	0	0	1058.98
Input_Municipal	0	0	928.36	0	0	928.36
Input_Other	21.33	6.20	2.86	0	0	30.40
Water Withdrawal	149.73	6.86	1861.15	0	0	2017.74
Wastewater Outfall	743.95	4.70	386.03	0	0	1134.68
Water Consumption[3]	-594.23	2.16	1475.12	0	0	883.06

3.1.1 Greenhouse Gas Emissions

Table 3-2 and **Error! Reference source not found.** show the GHG emissions associated with the IGCC plant operations without CCS per MWh delivered to the end user. Although some CH_4 is emitted during Stage #1, the CO_2 emissions during Stage #3 dominant the LC. The SF_6 emissions caused by leakage during transmission are small and not visible in the figure when compared to CO_2, even on a GWP basis.

[3] For the coal mine operations, water output includes storm water and a small amount of sanitary wastewater (EPA, 2008a), which equals more than the water withdrawal and consumption, therefore producing a negative value for the overall water consumed. This value does not mean that the mining process creates water, only that storm water is processed during operation.

Table 3-2: Greenhouse Gas Emissions for Case 1

Emissions (kg CO_2 Eq. /MWh)	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: IGCC without CCS	Stage #4: Transmission & Distribution	Total
CO_2	2.83	13.14	841.92	0.00	857.90
N_2O	0.01	0.01	0.01	0.00	0.03
CH_4	69.30	0.42	0.04	0.00	69.75
SF_6	1.5E-06	8.0E-07	7.0E-03	3.27	3.27
GWP	72.15	13.57	841.97	3.27	930.95

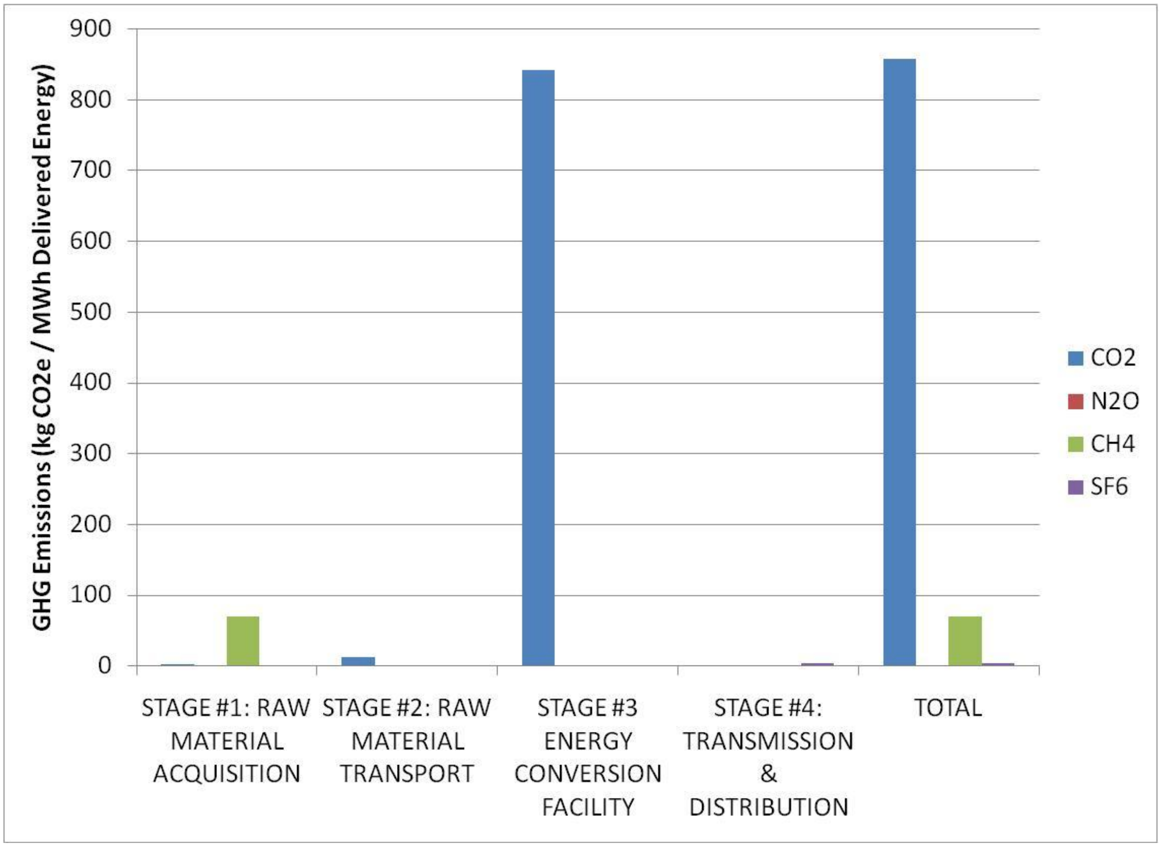

Figure 3.0-1 GHG Emissions (kg CO2e/MWh Delivered Energy) for Case 1, IGCC without CCS

3.1.2 Air Emissions

When compared to GHG emissions, particularly CO_2, all other air emissions are emitted on a much smaller scale. This is due mainly to the regulations placed on all criteria and hazardous air emissions; because all operations assume best practice management of emissions, most operations include some control measures. Although the scope of this study focuses on only the inventory of these emissions and conclusions are drawn only on a mass-emitted basis, one could draw further conclusions using available impact assessment methodologies (Bare, Norris *et al.*, 2003; SCS, 2008). **Figure 3.0-2** shows the air pollutant emissions (kg/MWh delivered) for the IGCC case without CCS.

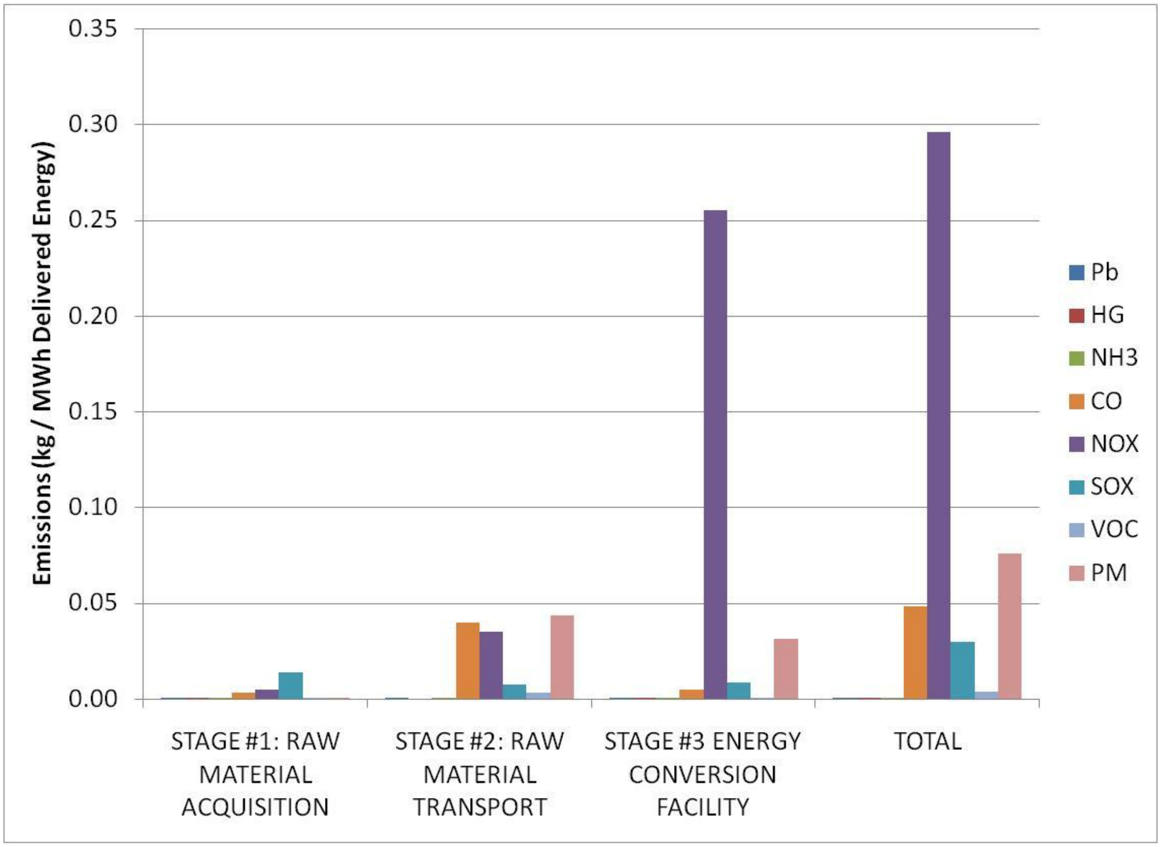

Figure 3.0-2 Air Emissions (kg/MWh Delivered) for Case 1, IGCC without CCS

The dominant air pollutant for IGCC without CCS is NO_X released during coal conversion (Stage #3). CO, NO_X, and SO_X are all emitted during fuel conversion. PM emissions are dominated by coal dust lost during train transport (Stage #2). All other pollutants (lead [Pb], Hg, NH_3, and volatile organic chemicals [VOCs]) contribute less than one percent to the total LC of air emissions.

3.1.3 Water Withdrawal and Consumption

Figure 3.0-3 shows the total water withdrawal and consumption for each stage and the total LC.

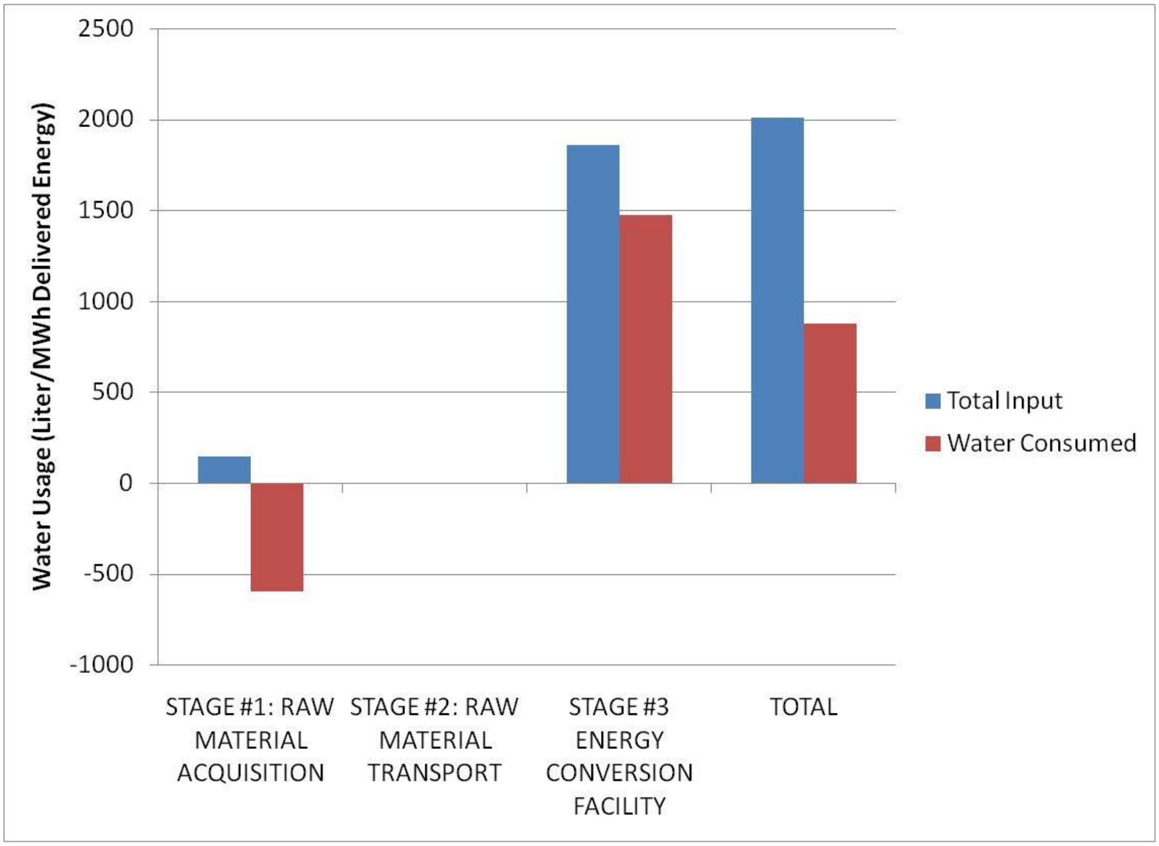

Figure 3.0-3 Water Withdrawal and Consumption for Case 1, IGCC without CCS

Water input and withdrawal and consumption is dominated by Stage #3 due to cooling water requirements in the power plant. The negative value for water consumed during Stage #1 is due to the additional output of storm water and is not due to water production during processes such as mining and coal cleaning. The amount of storm water processed by mine wastewater treatment affects the energy use and pollutant emissions during operation, and is therefore important to consider.

3.2 LCI results: IGCC with CCS

Table 3-3 summarizes all water withdrawals and emissions from the IGCC with CCS case, in kg/MWh, for each stage and the total LC. As with Case 1 (without CCS), no environmental impacts are associated with Stage #5. Similarly, only GHG emissions associated with SF_6 leakage are included in Stage #4. Therefore, Stage #5 will not be discussed further, and Stage #4 will only be included when discussing GHG emissions.

Table 3-3: Water and Emissions Summary for Case 2, IGCC with CCS

Parameters	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: Energy Conversion Facility (with CCS)	Stage #4: Transmission & Distribution	Stage #5: End User	Total
GHG Emissions kg/MWh						
CO_2	3.38	15.69	111.40	0	0	130.48
N_2O	5.3E-05	3.8E-05	4.2E-05	0	0	1.3E-04
CH_4	3.3E+00	0.02	2.0E-03	0	0	3.33
SF_6	7.8E-11	4.2E-11	3.5E-07	1.4E-04	0	1.4E-04
Air Polluants (non GHG) kg/MWh						
Pb	3.5E-07	2.1E-07	1.6E-05	0	0	1.7E-05
Hg	5.2E-08	1.6E-08	2.8E-06	0	0	2.8E-06
NH_3	2.9E-05	5.7E-04	4.8E-06	0	0	2.3E-04
CO	4.1E-03	4.8E-02	8.4E-03	0	0	3.0E-02
NO_X	6.2E-03	4.2E-02	2.5E-01	0	0	2.7E-01
SO_X	1.7E-02	9.3E-03	1.5E-02	0	0	3.5E-02
VOC	1.2E-04	3.9E-03	3.7E-04	0	0	1.8E-03
PM	1.1E-03	5.2E-02	3.7E-02	0	0	5.6E-02
Water Withdrawal and Consumption kg/MWh						
Input: Ground	153.4	0.8	1311.2	0	0	1465.3
Input: Municipal	0.0	0.0	1306.5	0	0	1306.5
Input: Other	25.5	7.4	3.1	0	0	36.0
Water Withdrawal	178.8	8.2	2620.8	0	0	2807.8
Wastewater Outfall	888.6	5.6	489.4	0	0	1383.6
Water Consumption	-709.7	2.6	2131.4	0	0	1424.2

3.2.1 Greenhouse Gas Emissions

Table 3-4 shows the GHG emissions from **Table 3-3** based on kg CO_2e.

Table 3-4: Greenhouse Gas Emissions for Case 2 in kg CO_2e/MWh

Emissions (kg CO_2/MWh)	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: IGCC W/CCS	Stage #4: Transmission & Distribution	Total
CO_2	3.38	5.48	111.40	0.00	120.27
N_2O	0.02	0.00	0.01	0.00	0.03
CH_4	82.77	0.18	0.05	0.00	82.99
SF_6	1.8E-06	5.7E-07	8.1E-03	3.27	3.28
Total GWP	86.17	5.66	111.47	3.27	206.57

Figure 3.0-4 compares the GHG emissions for each stage. CO_2 emitted during Stage #3 is the dominant GHG emissions throughout the LC (60 percent of the total emissions), which is expected as that stage is where all of the coal conversion occurs. However, when considered on a kg CO_2e basis, CH_4 contributes approximately 38 percent of the total due to emissions during coal mining (Stage #1). Although SF_6 has the largest GWP potential, the small mass emittance translates to only a 1.5 percent impact on the overall GHG emissions.

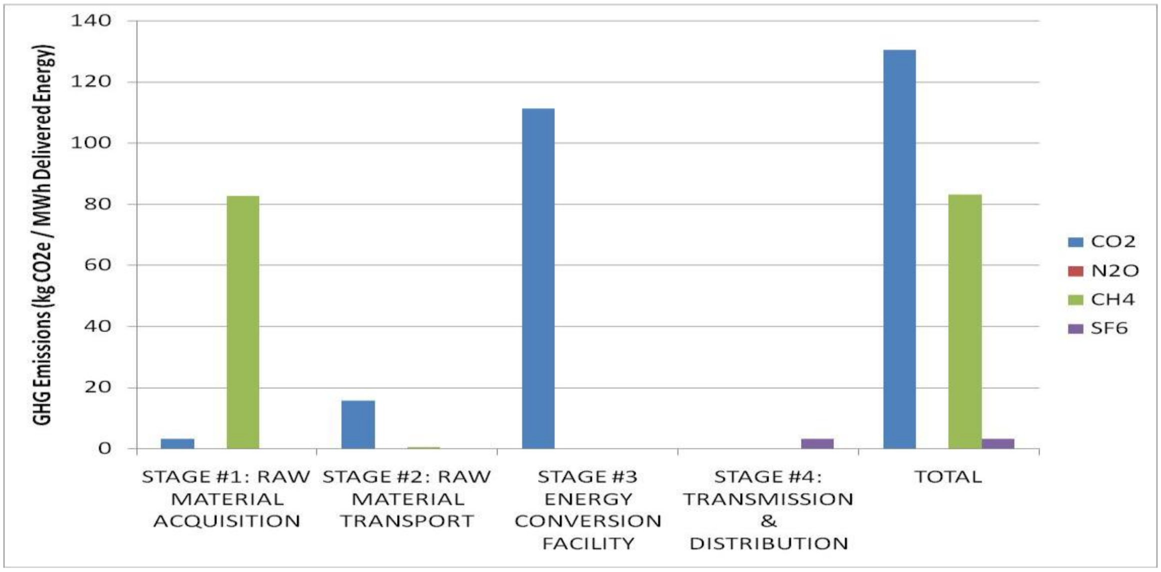

Figure 3.0-4 GHG Emissions on a Mass and CO2e Basis for Case 2, IGCC with CCS

3.2.2 Air Emissions

Figure 3.0-5 compares the air emissions for each stage and the total LC. As with Case 1, the dominate air pollutant for IGCC with CCS is NO_X released during coal conversion (Stage #3). CO, NO_X, and SO_X are all emitted during fuel conversion. PM emissions are dominated by coal dust lost during train transport (Stage #2). All other pollutants (Pb, Hg, NH_3, and VOC) contribute less than one percent to the total LC of air emissions.

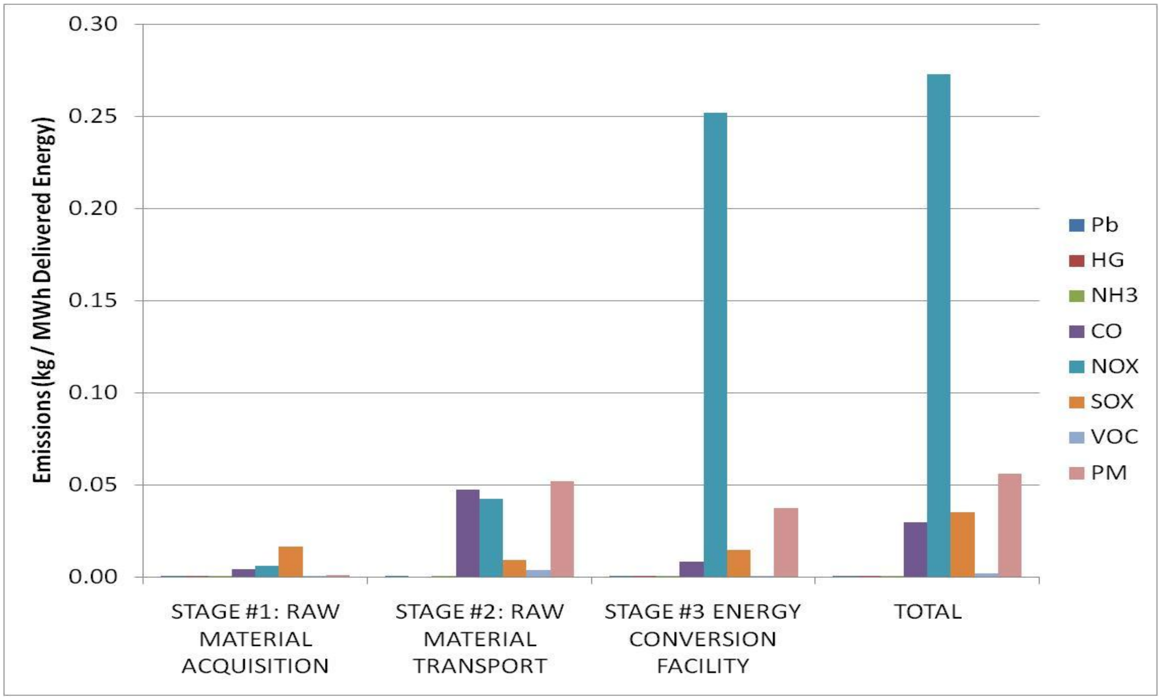

Figure 3.0-5 Air Emissions in kg/MWh for Case 2, IGCC with CCS

3.2.3 Water Withdrawal and Consumption

Figure 3.0-6 shows the total water withdrawal and consumption for each stage and the total LC.

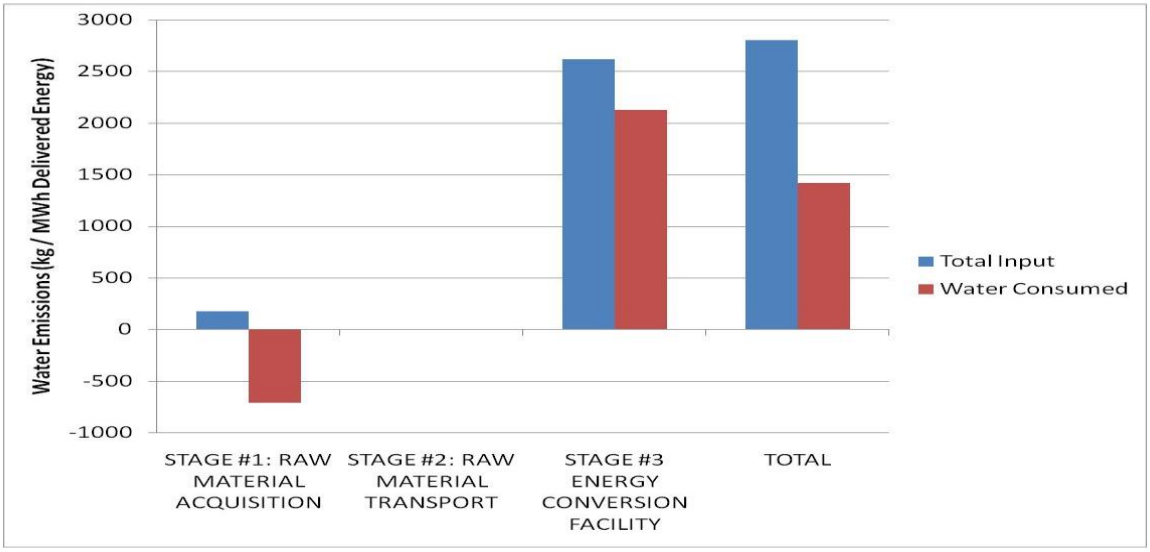

Figure 3.0-6 Water Withdrawal and Consumption for Case 2, IGCC with CCS

Water withdrawal and consumption is dominated by Stage #3 due to cooling water requirements in the power plant. Additionally, the CCS operation requires more cooling water for CO_2 compression. As with Case 1, the negative value for water consumed during Stage #1 is due to the additional output of storm water and is not due to water production during the mining processes. The amount of storm water processed by the mines wastewater treatment affects the energy use and emissions during operation, and is therefore important to consider.

3.3 Land Use Change

Analysis of land use effects associated with a process or product is considered a central component of an LCI investigation, under both ISO 14044 and American Society for Testing and Material Standards (ASTM) procedure. For the purposes of this study, land use encompasses the changes in the type or nature of activity that occurs in the land area considered within the study boundary.

3.3.1 Definition of Primary and Secondary Impacts

Land use effects can be roughly divided into primary and secondary. In the context of this study, primary land use effects occur as a direct result of the LC processes needed to produce electricity via IGCC. Primary land use change is determined by tracking the change from an existing land use type (native vegetation or agricultural lands) to a new land use that supports production; examples include coalmines, biomass feedstock cropping, and energy conversion facilities.

Secondary land use effects are indirect changes in land use that occur as a result of the primary land use effects. For instance, if the primary effect is the conversion of agriculture land to a coalmine in a rural area, a secondary effect might be the migration of coalmine employees to the mine site causing increased urbanization in surrounding areas. Due to the uncertainty in predicting and quantifying secondary effect, only primary effects are considered within the scope of this study.

3.3.2 Land Use Metrics

A variety of land use metrics, which seek to numerically quantify changes in land use, have been devised in support of LCI. Two common metrics in support of a process-oriented LCI are transformed land area (square meters of land transformed) and GHG emissions (kg CO_2e). The transformed land area metric estimates the area of land that is altered from a reference state, while the GHG metric quantifies the amount of carbon emitted in association with that change. **Table 3-5** summarizes the land use metrics included in this study.

Table 3-5: Primary Land Use Change Metrics Considered in this Study

Metric Title	Description	Units	Type of Impact
Transformed Land Area	Area of land that is altered from its original state to a transformed state during construction and operation of the advanced energy conversion facilities.	square meters (acres)	Primary
Greenhouse Gas Emissions	Emissions of greenhouse gases associated with land clearing/transformation.	kg CO_2e (lbs CO_2e)	Primary

For this study, the assessment of GHG emissions included those emissions that would result from the combustion of diesel fuel during the construction of the indicated facilities, for all LC stages. Additional considerations for the GHG emissions metric have been suggested, including quantifying the amount of carbon released from vegetation and soil organic matter as a result of construction activities, or quantification of the amount of carbon that would have been sequestered had no land use change occurred (Fthenakis and Kim 2008; Canals and others 2007; Koellner and Scholz 2007). However, no standardized or widely accepted methodology has been developed to quantify these emissions, and no further consideration of these issues is provided within the framework of this study.

Additional metrics, such as potential damage to ecosystems or species, water quality changes, changes in human population densities, quantification of land quality (e.g., farmland quality), and many other land use metrics may conceivably be included in a land use analysis. However, much of the data needed to support accurate analysis of these metrics are severely limited in availability (Canals, Bauer *et al.*, 2007; Koellner and Scholz, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area is quantified for this study.

3.3.3 Methodology

As previously discussed, the land use metrics used for this analysis quantify the land area that is transformed from its original state due to construction and operation of the IGCC plant and supporting facilities. Results from the analysis are presented as per the reference flow for each relevant LC stage, or per MWh when considering the additive results of all stages.

3.3.3.1 Transformed Land Area

The transformed land area metric was evaluated using satellite imagery and aerial photographs to assess and quantify the land use reference state. For this study the original state was either agricultural, forest, or grassland; it can be assumed that urban, residential, and other land uses would be avoided during the siting of a facility. Assumed facility locations and sizes are shown in **Table 3-6** and **Table 3-7**. The facility sizes and locations used elsewhere in this LCI were incorporated into the land transformed metric for consistency. Only LC Stage #1, Stage #2, and Stage #3 include installation of facilities in support of the IGCC pathway. No land use change occurred in LC Stage #4 and Stage #5; the transmission line infrastructure was considered existing and therefore installation (land use) was not included in the system boundary (**Section 1.2**).

Table 3-6: IGCC Facility Locations and Sizes

LC Stage No.	Facility	Location
LC Stage #1	Coal Mine	Southern IL, near Galatia, IL
LC Stage #2	Rail Spur	Southern IL, near Galatia, IL
LC Stage #3	IGCC	Southern MS
	Trunkline	Southern MS
	CCS Pipeline	Southern MS
LC Stage #4-5	Not Considered	Not Considered

Removal of onsite, existing land use was assumed to be complete (100 percent removal) for all facilities except the coalmine. Assessment of the existing Galatia Mine (Saline County, Illinois) indicated that coal cleaning facilities, wastewater treatment ponds, storage areas, loading facilities, and other facilities associated with the coal mine were distributed across the coal mine site and that approximately half of the mine site retained pre-existing land use characteristics. Therefore, the land use analysis of the coal mine assumes that half of the total mine site area would be converted from its original state land use. **Table 3-7** summarizes the facility sizes that were assumed for this analysis.

Table 3-7: Key Facility Assumptions

Facility	Total Area	Units	Key Assumptions
Coal Mine	6,916,077 (1,709)	m^2 (acres)	Based on Galatia Mine, IL; 50 percent of land area is used for facilities
Rail Spur	374,028 (92)	m^2 (acres)	126 inch track width plus additional 20 feet gravel/cleared area; 25 mile length
IGCC	121,406 (30)	m^2 (acres)	30 acres assumed based on similar plant footprints and Baseline Report
Trunkline	367,896 (91)	m^2 (acres)	30 foot width, 1 mile length
CCS Pipeline	2,452,640 (364)	m^2 (acres)	50 foot construction width, 100 mile length

Due to its proximity to the coalmine, original state land use for the rail spur was assumed to consist of the same proportion of agricultural, forest, and grassland as the coal mine site. This assumption is reasonable given generally similar original state land use types in the proximity of the coal mine site, and assuming that the rail spur would not be routed through a city or large water feature. Similarly, assessment of the original state land use for the trunkline and CCS sequestration pipeline, as applicable, were assumed to consist of the same proportion of original state land uses as the IGCC site.

Following decommissioning, it was assumed for the purposes of the land use analysis that all transformed land area would be re-seeded or planted as grassland. Results from the transformed land area analysis are reported per the relevant reference flow for each LC stage, and per one MWh electricity delivered to the consumer, assuming a seven percent grid loss.

3.3.3.2 Transformed Land Area

Results from the analysis of land use at the coal mine site indicated three primary land use categories: forest, grassland, and agriculture. As shown in **Figure 3.0-7**, agriculture accounts for most of the total area (72 percent), followed by forest (26 percent) and grassland (two percent). Minor areas containing other land uses, such as roads or waterways, were allocated to one of these three categories. As previously discussed, due to its proximity to the coal mine site, the proportion of each existing land use category (e.g., proportion of agriculture/forest/grassland) for the coal mine was also applied to the rail spur.

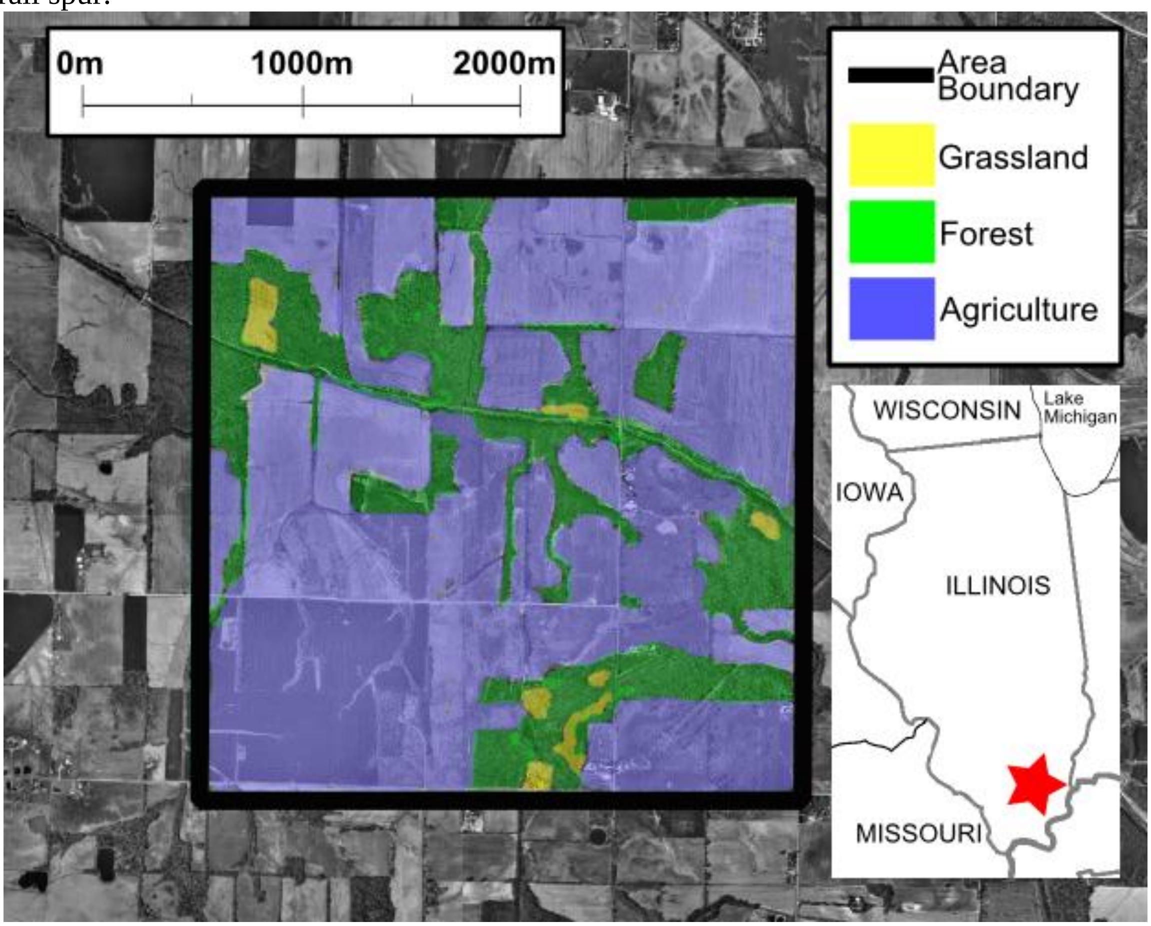

Figure 3.0-7 Existing Condition Land Use Assessment: Coal Mine Site

Results from the analysis of land use at the IGCC site indicated two primary land use categories: forest and grassland. As shown in **Figure 3.0-8**, forest accounts for most of the total area (95 percent), followed by grassland (five percent). Similar to the analysis at the coal mine site, small areas containing other land uses, such as roads or waterways, were allocated to one of these two categories, as relevant. As previously discussed, due to proximity to the IGCC site, the proportion of each existing land use category (e.g., proportion of forest/grassland) for the IGCC site was also applied to the trunkline and CCS pipeline.

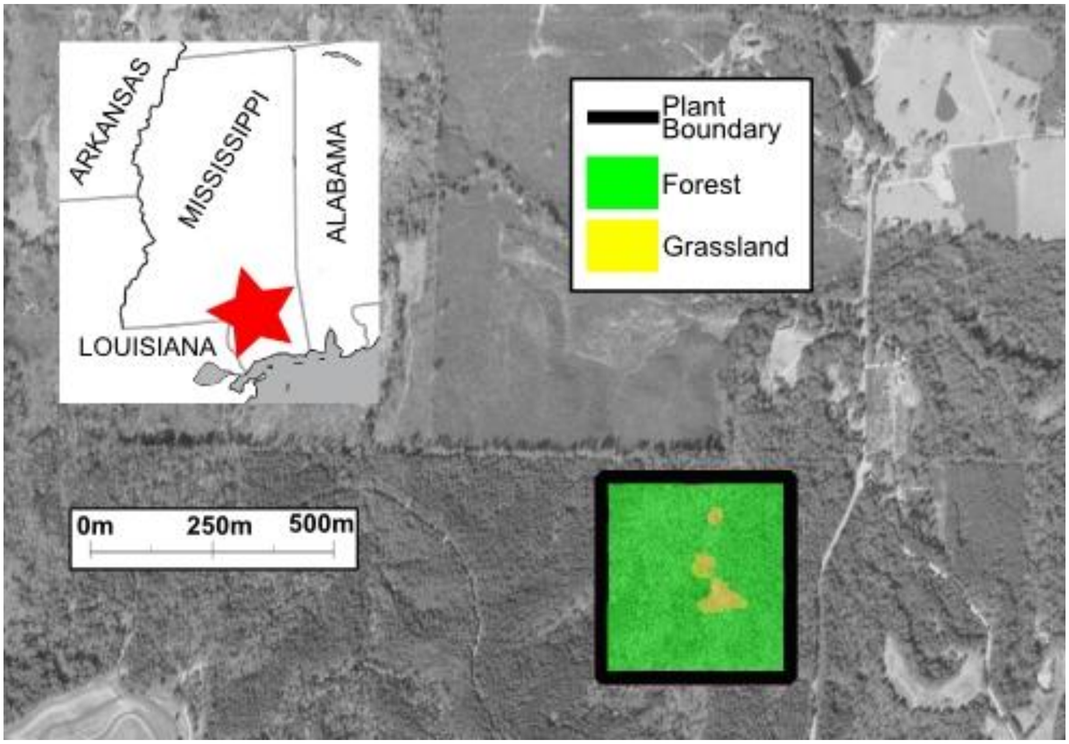

Figure 3.0-8 Existing Condition Land Use Assessment: IGCC Site

The total amounts of transformed land, which includes land area associated with the coal mine, rail spur, IGCC, trunkline, and, as relevant, the CCS pipeline, are shown in **Table 3-8** and **Table 3-9**. Production at the coal mine is assumed to be constant over the lifetime of the facility (5.99 million tonnes/yr production rate), and the IGCC cases would require only a portion of the total coal mined (1.56 million tonnes/yr without CCS; 1.59 million tonnes/yr with CCS) (NETL, 2010). Therefore, transformed land area for the coalmine is calculated based on the total annual production rate of the mine, and not on the amount of coal required specifically to feed the IGCC plant. As a result, coalmine transformed land area per kg of coal produced at the coal mine does not change between the two cases (with and without CCS).

As shown, the total transformed land area per kg of coal transported along the rail spur would be less for the case with CCS than for the case without CCS. This is because more coal would be transported under the case with CCS, yet the rail spur would be the same size under both cases. The IGCC and trunkline would be the same size for the cases with and without CCS; however the transformed land area per MWh for these two facilities would be greater for the case with CCS, because it has a lower production capacity.

Table 3-8: Total Transformed Land Area: Without CCS Case

Category		Coal Mine	Rail Spur	IGCC	Trunkline
Units per Reference Flow		m^2/kg coal produced	m^2/kg coal transported	m^2/MWh	m^2/MWh
Transformed Land Area	Grassland	3.84×10^{-7}	1.60×10^{-7}	4.51×10^{-5}	1.37×10^{-4}
	Forest	5.00×10^{-6}	2.08×10^{-6}	8.57×10^{-4}	2.60×10^{-3}
	Agriculture	1.38×10^{-5}	5.77×10^{-6}	n/a	n/a
Total Transformed Land Area		1.92×10^{-5}	8.01×10^{-6}	9.02×10^{-4}	2.73×10^{-3}

Table 3-9: Transformed Land Area: With CCS Case

Category		Coal Mine	Rail Spur	IGCC	Trunkline	CO_2 Pipeline
Units		m^2/kg coal produced	m^2/kg coal transported	m^2/MWh	m^2/MWh	m^2/MWh
Transformed Land Area	Grassland	3.84×10^{-7}	1.57×10^{-7}	5.20×10^{-5}	1.57×10^{-4}	1.05×10^{-3}
	Forest	5.00×10^{-6}	2.04×10^{-6}	9.87×10^{-4}	2.99×10^{-3}	1.99×10^{-2}
	Agriculture	1.38×10^{-5}	5.64×10^{-6}	n/a	n/a	n/a
Total Transformed Land Area		1.92×10^{-5}	7.84×10^{-6}	1.04×10^{-3}	3.15×10^{-3}	2.10×10^{-2}

Table 3-10 shows the total transformed land, aggregated and by land type, for each case per 1-MWh delivered energy. Differences between the cases are small and the increase in land change in Case 2 can be attributed to the CO_2 pipeline, as well as the high coal input and lower net output due to power needs of the CCS operation.

Table 3-10: Total Transformed Land, m^2/MWh Delivered Energy

Land Type	Case 1: without CCS	Case 2: with CCS
	m^2/MWh	m^2/MWh
Grassland	3.99E-04	1.59E-03
Forest	6.47E-03	2.88E-02
Agriculture	7.30E-03	8.54E-03
Total	1.41E-02	3.90E-02

3.4 Comparative Results

3.4.1 Comparative LCC Results

Comparatively, the two IGCC cases are similar in that approximately half of the total LCC is contributed to capital costs. The LCC for the case with CCS exceeds the LCC for the case without CCS due to the additional capital, utility, and operating needs of the CO_2 compression and removal system at the plant and the CO_2 TS&M system. Also contributing to the higher costs at the IGCC plant with CCS is the reduction in net-output of the plant, meaning that on a kW-basis, costs will be higher. Comparison of the LCOE results for the two cases show the same trends as the LC cost results. Overall, the total LCOE results for the IGCC case with CCS exceed the LCOE results for the IGCC case without CCS by 36 percent. A summary of the LCOE by cost component for each case is given in **Table 3-12**, and represented graphically in **Figure 3.0-9**.

Table 3-12: Comparison of IGCC Cases without and with CCS for LCOE

LCOE ($/kWh)	IGCC wo-CCS	IGCC w-CCS	Change
Utility Costs (Feedstock + Utilities)	$0.0220	$0.0263	20%
Labor Costs	$0.0173	$0.0227	31%
Variable O&M Costs	$0.0112	$0.0143	28%
Capital Costs	$0.0689	$0.0935	36%
CO_2 TS&M Costs		$0.0053	
Total LCOE	$0.1194	$0.1621	36%

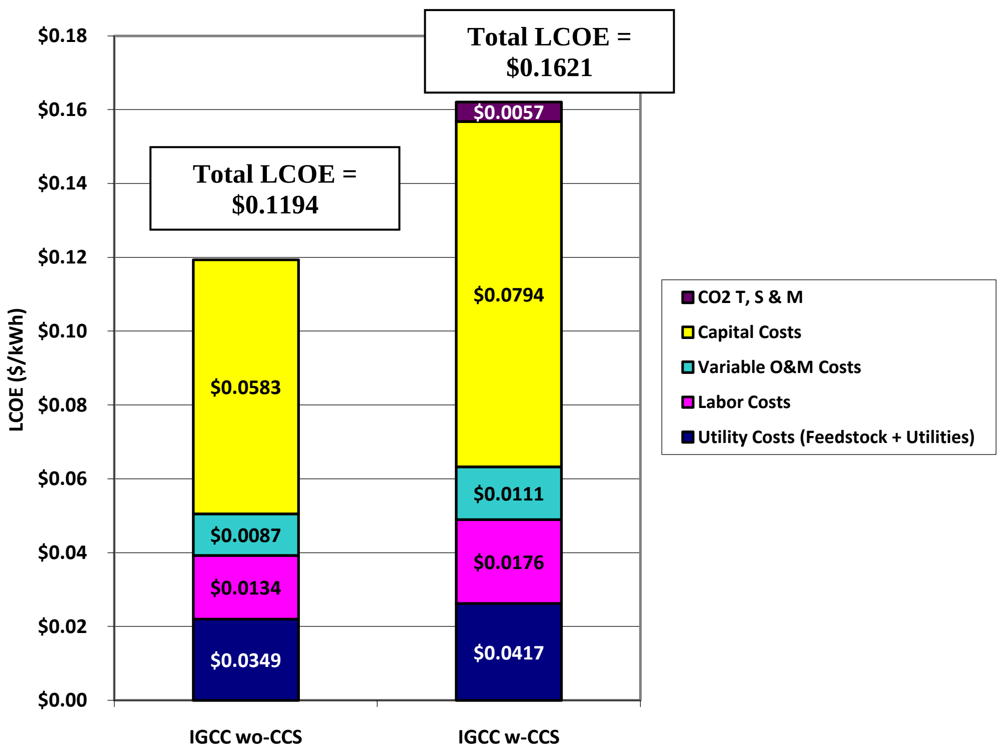

Figure 3.0-9 Comparative LCOE ($/KWh) for IGCC Case 1(without CCS) and Case 2 (with CCS)

3.4.1.1 Global Warming Potential

Figure 3.0-10 compares the GHG emissions (kg CO_2e/MWh delivered) for Case 1 (without CCS) and Case 2 (with CCS). It is clear that, based on the modeling assumptions made throughout this study, adding CCS to an IGCC facility does reduce the

GWP over the LC. Even with an increase in coal consumption in Case 2[4] (to account for additional auxiliary needs associated with CCS) (NETL, 2010), approximately 77 percent less GHGs are emitted over the total LC. CH_4 emissions for Case 2 are slightly higher due to the increased coal input. It is interesting to note that when considering Case 2, total CH_4 emissions (on a CO_2e basis) account for almost 40 percent of the total GHG emissions; much more than the eight percent impact of CH_4 in Case 1. SF_6 emissions are not seen as a large contributor to the total GWP of either case, with a 1.5 percent impact to Case 2 (and less than one percent for Case 1). Therefore, one can conclude that although SF_6 has a large GWP (22,800 CO_2e) (IPCC, 2007), when multiplied by the small mass emitted it does not correlate to a large overall impact.

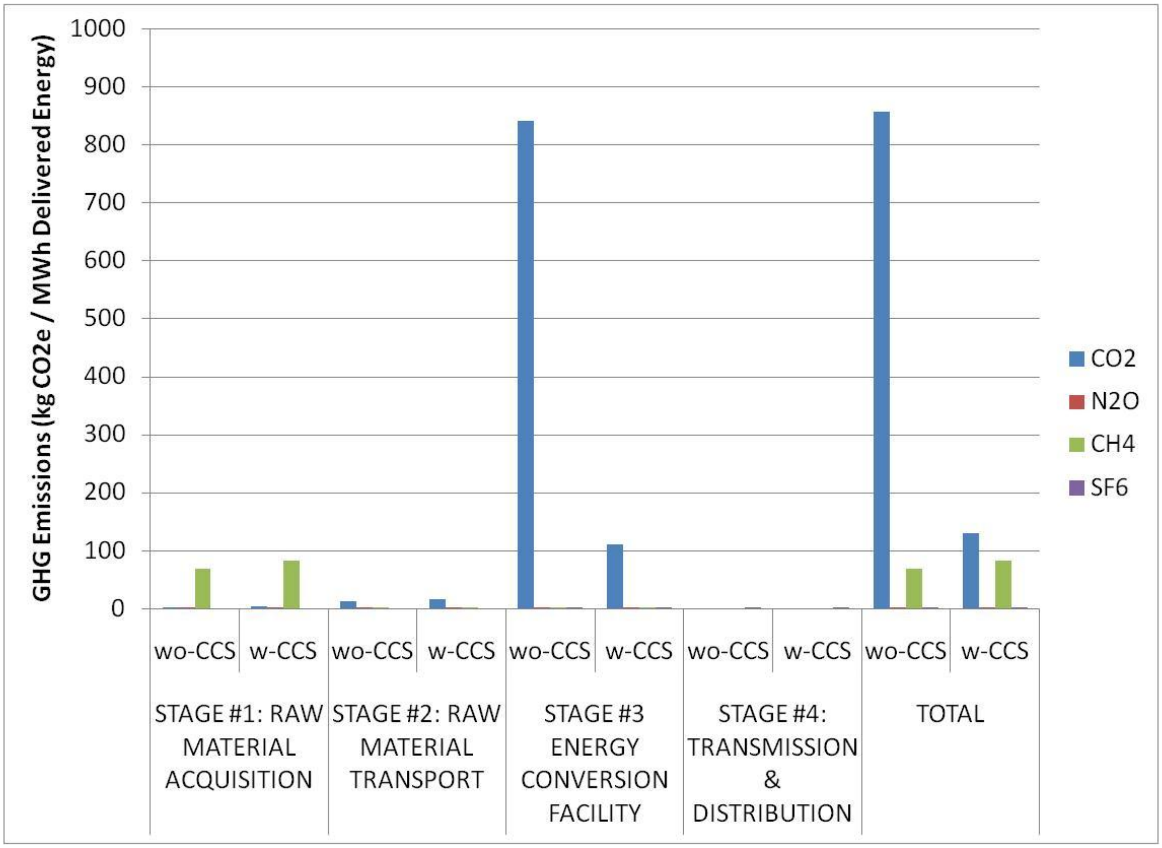

Figure 3.0-10 Comparative GHG Emissions (CO2e/MWh Delivered) for Case 1 (without CCS) and Case 2 (with CCS)

3.4.1.2 Comparative Air Pollutant Emissions

Figure 3.0-11 compares the non-GHG air pollutants between the two cases on a kg/MWh delivered energy basis. During evaluation of the air pollutant LCI for each case (**Section 3.1.2** and **Section 3.2.2**), it was shown that Pb, Hg, NH_3, and VOC had impacts below the

[4] To model two IGCC plants with similar MWh outputs, the Baseline Report assumes a two percent increase in coal input for the Case 2, IGCC with CCS (NETL, 2010). Even with additional coal resources, Case 2 still outputs less MWh than Case 1 (IGCC without CCS), but the two are as similar as possible considering equipment capacities and other factors (NETL, 2010).

cut-off criteria for both cases (on a unit process basis). Therefore, to simplify **Figure 3.0-11**, those emissions are not included in this comparison.

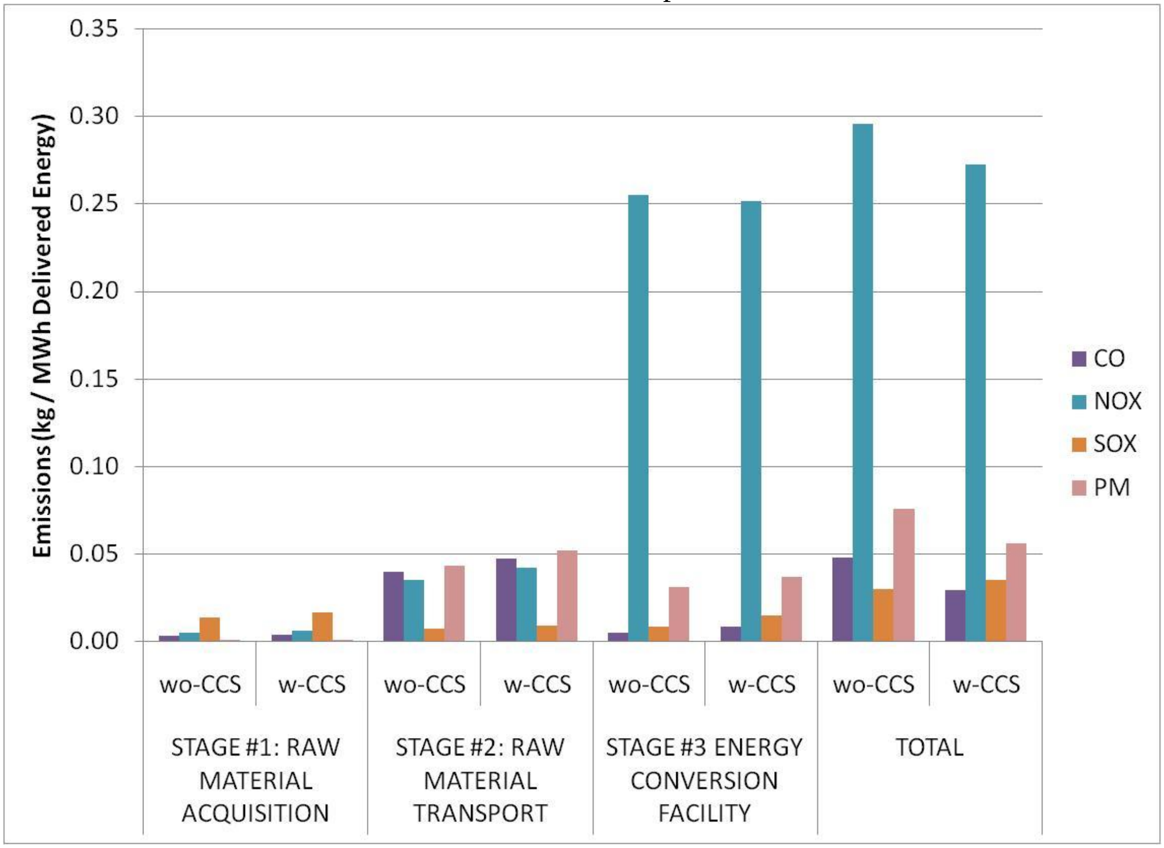

Figure 3.0-11 Comparison of Air Emissions (kg/MWh Delivered Energy) for Case 1(IGCC without CCS) and Case 2 (IGCC with CCS)

A slight increase in the major combustion emissions (NO_X, SO_X, and CO) is seen for Case 2; this is due to the increased coal input needed to satisfy the additional auxiliary needs of the CCS system (NETL, 2010). A small increase in PM emission is also seen, but due to the same factor. The addition of pipeline installation/deinstallation in Case 2 showed less than a one percent overall impact on additional air pollutant emissions in Stage #3. Therefore, besides the need for additional energy to run the CCS, no real tradeoffs can be seen between GHG control and other air pollutants. However, primary source data would need to be collected (actual plant emissions from an IGCC plant with CCS) to confirm that CO_2 capture does not have an adverse impact on the ability of other control technologies used to reduce criteria and hazardous air emissions.

3.4.1.3 Comparative Water Withdrawal and Consumption

Some tradeoff is seen for water withdrawal and consumption when the two cases are compared, as shown in **Figure 3.0-12**.

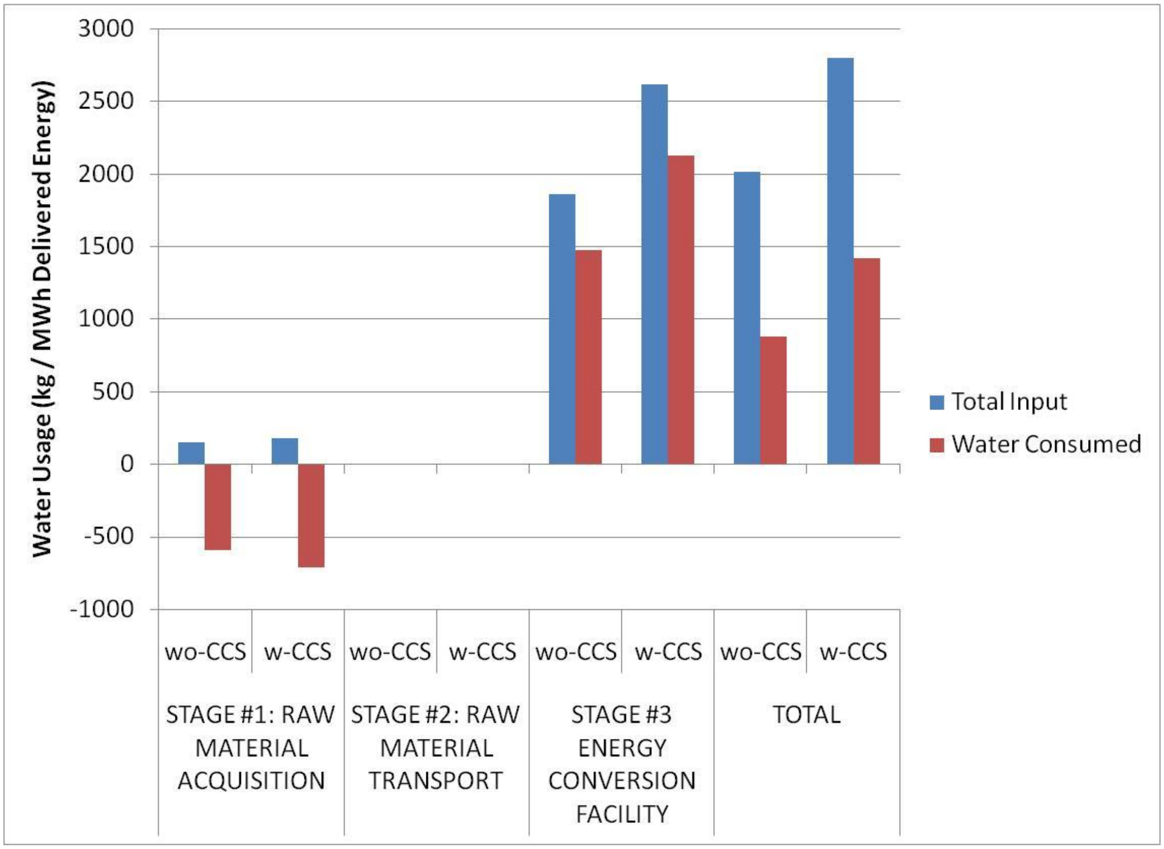

Figure 3.0-12 Comparative Water Withdrawal and Consumption for Case 1 (IGCC without CCS) and Case 2 (IGCC with CCS)

The increase in water withdrawal (23 percent) for the case with CCS is due to additional cooling water needs during the carbon capture process.

3.4.1.4 Comparative Land Use Transformation

The total transformed land area for all LC stages combined is shown in **Figure 3.0-13,** on a per MWh delivered basis. Land use change for the case with CCS is more than twice that of the case without CCS. This is due to the additional land area required for the CCS pipeline, as well as the parasitic load of the CCS, which results in reduced power plant output and greater feedstock requirements per MWh output. Because the pipeline and IGCC plant were assumed to be developed on forestland, the largest transformation is for that land type. A small amount of agricultural and grassland were assumed to be used when developing the coal mine, but the amount is minimal when compared to forest.

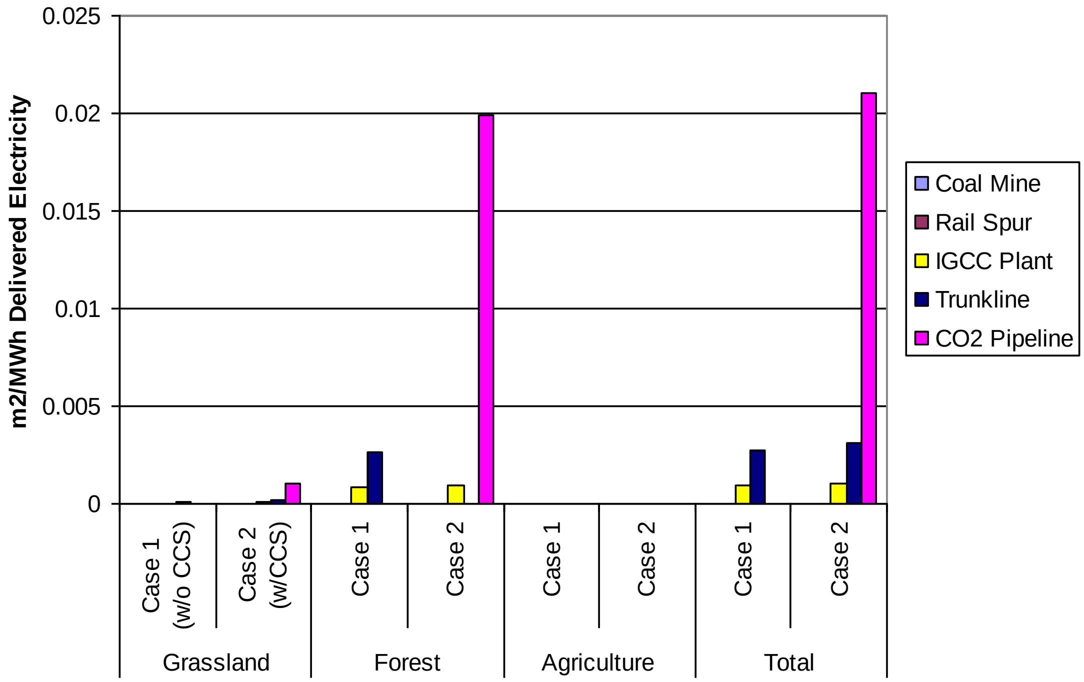

Figure 3.0-13 Total Transformed Land Area for IGCC Case 1 (without CCS) and Case 2 (with CCS)

3.5 Sensitivity Analysis

Sensitivity analysis is a "what-if" analysis approach that identifies the impact of system parameters, including assumptions, on the final results. The outcome of a sensitivity analysis is the knowledge of the magnitude of the change of an output for a given variation of a system parameter. A final result is said to be sensitive to a parameter if a small change in the parameter gives the result of a larger change in a final result.

Another application for sensitivity analysis is when uncertainty exists about a parameter. Reasons for the uncertainty could be due to an absence of data regarding the construction estimates for an energy conversion facility or due to a questionable emissions profile for a specific piece of equipment to name a few. Knowing the effect that a parameter has on final results can therefore reduce the uncertainty about the parameter.

3.5.1 Sensitivity Analysis of Cost Assumptions

To test the sensitivity of LCC for the IGCC cases with and without CCS, capital and variable O&M costs for all components as well as fuel/feed costs from AEO 2008 were varied (**Table 3-13**).

Table 3-13: LCC Uncertainty Analysis Parameters

Parameter	Uncertainty Range
Capital Costs (CC)	+/-30%
Variable O&M Costs	+/-30%
AEO Values	Reference Case/High Case
Total Tax Rate	+/-10%
Capacity Factor	+/-5%

The sensitivity of the LCC results to the fluctuation of capital and variable O&M costs was analyzed by inflating and deflating each by a factor of 30 percent, based on the Baseline Report's stated accuracy rating (NETL, 2010). This 30-percent range was applied to the capital costs for all major components of the LC as well as the CO_2 pipeline and injection well for the case with CCS.

The base case used AEO reference case values as the primary data set. Values from the AEO high price case were used to analyze the sensitivity of the LC to variation in feed/fuel and utility prices.

The total tax rate used for the base case is 38.9 percent. This was varied by +/-10 percent. The range is 35.0 percent on the low side and 42.8 percent on the high side to account for possible fluctuation in taxes at both the Federal and state levels.

For the base case, the capacity factor is set at 80 percent. To test the sensitivity of the LCC to a change in the capacity factor, the capacity factor was varied from 75 percent to 85 percent.

3.5.1.1 Sensitivity Analysis Results for Case 1: IGCC without CCS

The results for the IGCC case without CCS uncertainty analysis indicate that the LCOE is most responsive to the change in capital costs by +/-30 percent. When capital costs for all major components of the IGCC without CCS LC are increased and decreased by 30 percent, the total LCOE of the plant increases and decreases by 17 percent, giving the LCOE a range of $0.0995kWh to $0.1394/kWh, as shown in **Figure 3.0-14** and **Figure 3.0-15**.

Varying the capacity factor by +/- five percent from the base case, 80 percent causes total LCOE to increase and decrease by approximately six to seven percent. This translates into a range of $0.1137/kWh to $0.1259/kWh.

Variable O&M costs increased and decreased by 30 percent, caused a slight 3 percent change in the total LCOE for the case. LCOE costs when O&M costs are increased and decreased had a range from $0.1161/kWh to $0.1228/kWh.

Increasing the total tax rate (Federal plus state) by +/-10 percent resulted in a percent change of +/- two percent. The range for this is $0.1167/kWh to $0.1222/kWh.

Little change occurred when feedstock and utility prices were increased by changing from the AEO reference case prices used in the base case to the AEO high price case.

Based on AEO values for the high price case, increased feed/fuel and utility prices present a change of 0.33 percent.

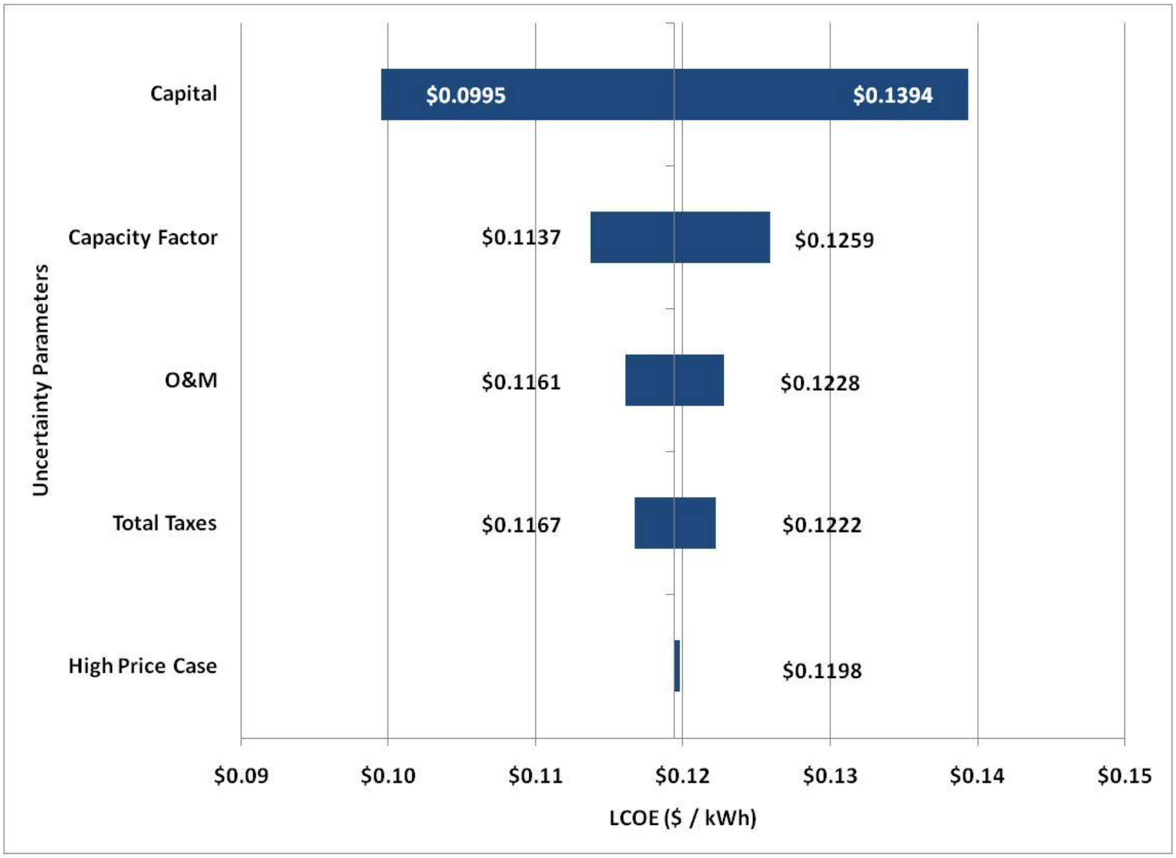

Figure 3.0-14 Analysis LCOE Ranges for the IGCC Case without CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

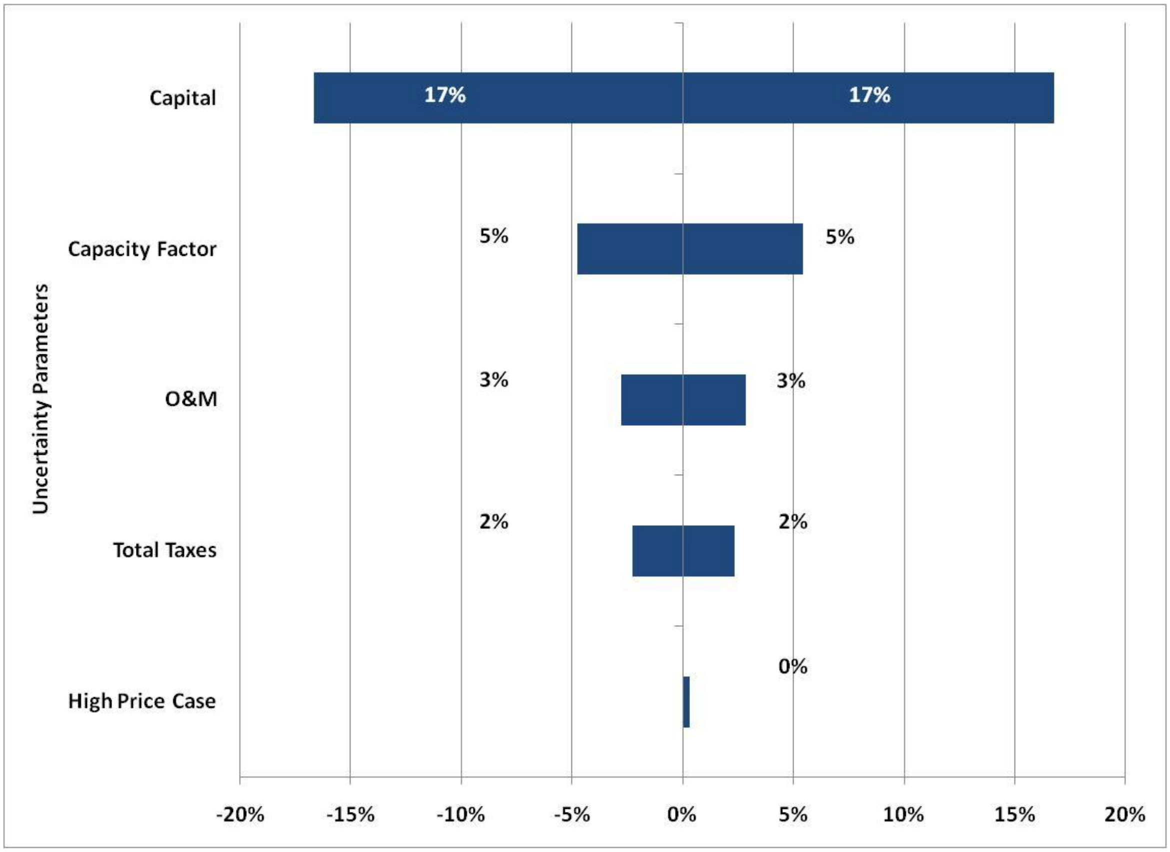

Figure 3.0-15 Change from Base Case LCOE for the IGCC Case without CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

3.5.1.2 Sensitivity Analysis Results for Case 2: IGCC with CCS

As with the IGCC case without CCS, the results indicate that a fluctuation in capital costs will cause the LCOE to change the most. When capital costs are varied by +/-30 percent, the total LC LCOE for the case has a range of $0.1349/kWh to $0.1894/kWh. This translates into a change of approximately 17 percent in both directions. Results for the LCOE values and percent change can be seen in **Figure 3.0-16** and **Figure 3.0-17**.

With a capacity factor range from 75 to 85 percent, the LCOE ranged from $0.1542/kWh to $0.1712/kWh. This is equal to a percent change of five to six percent.

Variation in the variable O&M costs by +/-30 percent resulted in an LCOE range from $0.1575/kWh to $0.1668/kWh. This is represented by a percent change of +/- two percent. Similarly, a variation of the total tax rate by 10 percent in both directions causes the LCOE to change by +/- two percent. This translates into a range of $0.1582/kWh to $0.1660/kWh.

The AEO 2008 high price case values showed little variation in the LCOE value. As a result of replacing the AEO 2008 reference case values used in the base case with the AEO 2008 high price case, the LCOE increased by less than one percent, 0.37 percent, meaning fluctuation in the coal feed price or the natural gas fuel price, based on the forecasted AEO values, will cause little variation in the total LC LCOE for the IGCC case with CCS.

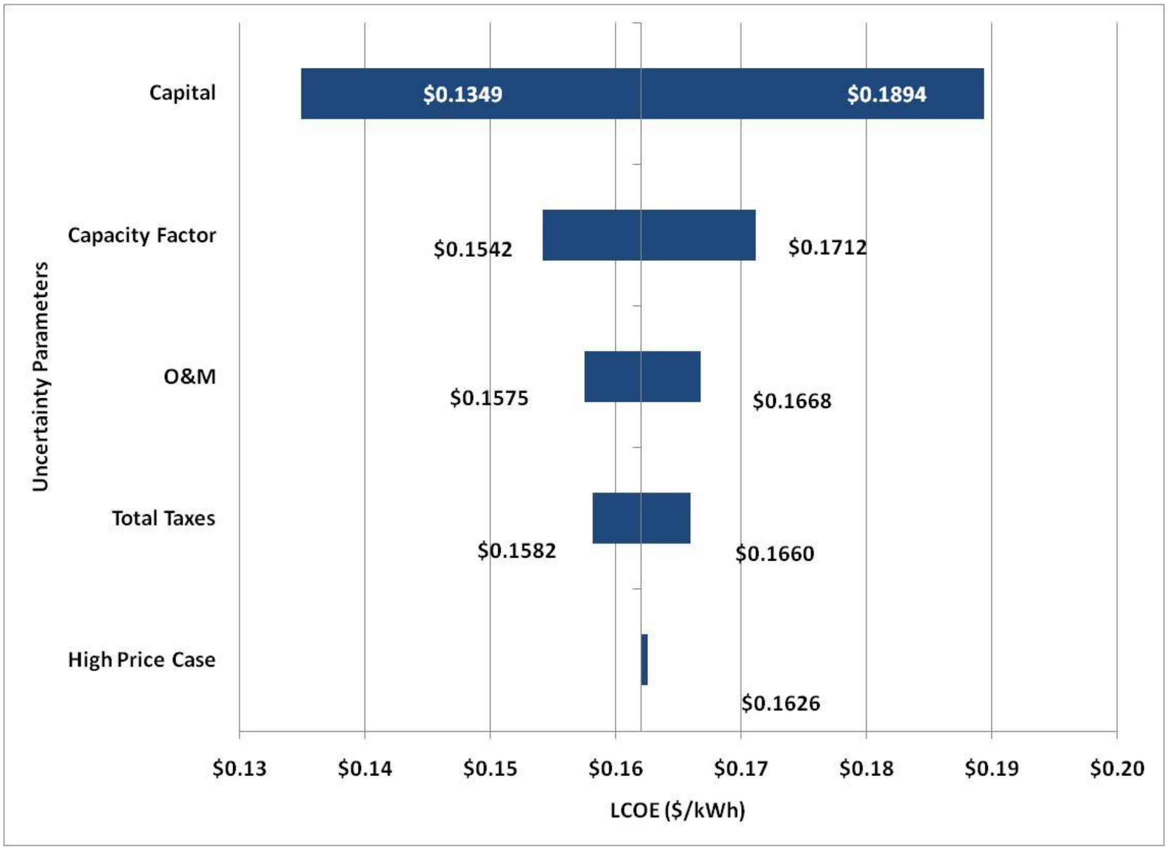

Figure 3.0-16 Analysis LCOE Results for the IGCC Case with CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

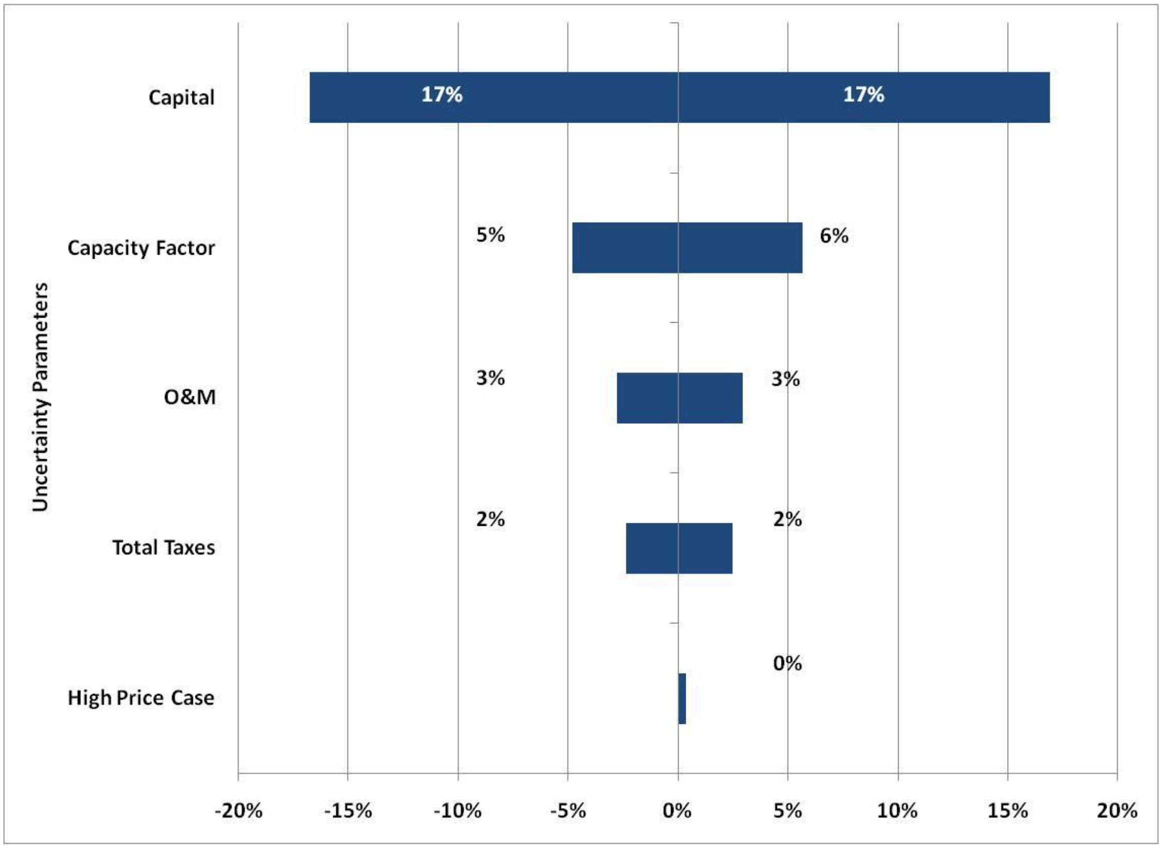

Figure 3.0-17 Percent change from Base Case LCOE for the IGCC Case with CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

3.5.2 Sensitivity Analysis of LCI Assumptions

For this study, sensitivity analysis is performed on a few key parameters listed in **Table 3-14**. These parameters were chosen based perceived impact and data quality.

Table 3-14: Sensitivity Analysis Parameters

Parameter	Stages Effected	Value in Model	Sensitivity Range/Value	Source/Reasoning
Materials	1, 3	Totals for steel, concrete, etc.	3 times increase (200 percent)	Arbitrary range to account for replacement parts, missed data.
Methane Emissions	1	360 ft^3 CH_4/ton coal	216 to 450 ft^3 CH_4/ton coal	Based on 40% methane recovery versus maximum Methane emissions based on average error from source (EPA, 2008c).
Rail line Distance	2	1170 miles	0 miles	Vary to zero to see if any impact is felt from this stage.

3.5.2.1 Construction Material Contributions

The effect of an additional three times the material input on GHG emissions for both IGCC cases are shown in **Table 3-15**. Only Stage #1, Stage #3, and total (all stages) emissions are shown as the GHG emissions for the remaining stages were not varied from the base case values presented in **Table 3-4**.

Table 3-15: GHG Emissions (kg CO_2e/MWh) for Base Cases and Sensitivity Impacts of Three Times the Material Inputs

Emissions (kg CO_2e /MWh)	Stage #1: Raw Material Acquisition			Stage #3: Energy Conversion			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
IGCC with CCS									
CO_2	3.4	3.7	7.2%	111.5	113.7	1.9%	130.7	133.1	1.8%
N_2O	1.6E-02	1.9E-02	19.2%	1.2E-02	3.3E-02	168.1%	1.4E-01	1.7E-01	16.7%
CH_4	83.1	83.2	0.0%	0.1	0.1	88.7%	83.8	83.8	0.1%
SF_6	1.8E-06	4.5E-06	149.8%	7.9E-03	7.9E-03	0.0%	3.3	3.3	0.0%
Total GWP	86.6	86.8	0.30%	111.6	113.8	1.99%	217.9	220.3	1.14%
IGCC without CCS									
CO_2	2.9	3.1	7.2%	857.4	858.8	0.2%	873.7	875.3	0.2%
N_2O	1.4E-02	1.6E-02	19.2%	6.3E-03	1.6E-02	152.9%	1.2E-01	1.3E-01	10.4%
CH_4	70.6	70.6	0.0%	0.0353	0.1	77.6%	71.1	71.2	0.0%
SF_6	1.5E-06	3.8E-06	149.8%	6.8E-03	6.8E-03	0.0%	3.3	3.3	0.0%
Total GWP	73.5	73.7	0.30%	857.4	858.9	0.17%	948.2	949.9	0.18%

From the calculation of total GWP one can see that, although the percentage increase of individual pollutants can be large, the overall percent increase is only 1.1 percent for IGCC with CCS and 0.18 percent for IGCC without CCS. This is because CO_2 emissions are dominated by coal combustion and CH_4 emissions by coal bed methane release, neither of which is impacted by construction materials. Therefore, construction material inputs have little impact on the overall GWP of either IGCC plant.

Table 3-16 and **Table 3-17** show the sensitivity of non-GHG air pollutants to material inputs for IGCC without and with CCS. NO_X and PM emissions, measurable pollutants in each cases, are only slightly sensitive to material inputs with increases of 1.2 and 2.1 percent, respectively for case 1 and 1.6 and 2.5 percent for case 2. Pb, VOC, and Hg are more sensitive, but even with the material input increase neither emission contributes more than one percent to the overall non-GHG life cycle emissions. CO emissions are sensitive to material inputs, showing a 15 and 22 percent increase when compared to the base case without and with CCS. Additional, a 7 and 10 percent increase is seen for SO_X emissions. This is because, after CO_2, CO and SO_X are the largest pollutant inventories in the concrete, steel plate, steel pipe, aluminum sheet, and cast iron manufacturing life cycle profiles. Therefore, some sensitivity is seen when considering construction material impacts on CO and SO_X emissions.

Table 3-16: IGCC without CCS Air Pollutant Emissions (kg /MWh) for the Base Cases and Sensitivity Impacts of Three Times the Material Inputs

Emissions (kg /MWh)	Stage #1: Raw Material Acquisition			Stage #3: Energy Conversion			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
IGCC without CCS									
Pb	3.01E-07	6.56E-07	118.2%	1.31E-05	1.41E-05	7.4%	1.36E-05	1.49E-05	9.8%
Hg	4.43E-08	6.45E-08	45.3%	2.54E-06	2.61E-06	2.4%	2.60E-06	2.68E-06	3.1%
NH_3	2.51E-05	2.56E-05	2.2%	3.29E-06	6.15E-06	87.1%	5.14E-04	5.17E-04	0.7%
CO	3.53E-03	5.10E-03	44.5%	4.99E-03	1.05E-02	109.6%	4.69E-02	5.39E-02	15.0%
NO_X	5.27E-03	5.66E-03	7.4%	2.41E-01	2.44E-01	1.2%	2.83E-01	2.86E-01	1.2%
SO_X	1.42E-02	1.47E-02	3.6%	5.85E-02	6.36E-02	8.7%	8.01E-02	8.57E-02	7.0%
VOC	1.03E-04	1.27E-04	23.5%	2.52E-04	3.64E-04	44.5%	3.69E-03	3.83E-03	3.7%
PM	9.01E-04	9.74E-04	8.1%	3.21E-02	3.37E-02	4.8%	7.72E-02	7.88E-02	2.1%

Table 3-17: IGCC with CCS Air Pollutant Emissions (kg /MWh) for the Base Cases and Sensitivity Impacts of Three Times the Material Inputs

Emissions (kg /MWh)	Stage #1: Raw Material Acquisition			Stage #3: Energy Conversion			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
IGCC with CCS									
Pb	3.54E-07	7.73E-07	118.2%	1.63E-05	1.91E-05	17.2%	1.68E-05	2.00E-05	19.2%
Hg	5.22E-08	7.59E-08	45.3%	2.96E-06	3.09E-06	4.4%	3.03E-06	3.18E-06	5.1%
NH_3	2.95E-05	3.02E-05	2.2%	4.76E-06	7.67E-06	61.1%	6.06E-04	6.10E-04	0.6%
CO	4.15E-03	6.00E-03	44.5%	8.30E-03	1.93E-02	132.5%	5.77E-02	7.05E-02	22.3%
NO_X	6.21E-03	6.67E-03	7.4%	2.44E-01	2.48E-01	1.7%	2.93E-01	2.98E-01	1.6%
SO_X	1.68E-02	1.74E-02	3.6%	5.32E-02	6.05E-02	13.7%	7.87E-02	8.66E-02	10.1%
VOC	1.21E-04	1.50E-04	23.5%	3.62E-04	5.72E-04	58.2%	4.41E-03	4.65E-03	5.4%
PM	1.06E-03	1.15E-03	8.1%	3.73E-02	3.94E-02	5.7%	9.03E-02	9.26E-02	2.5%

3.5.2.2 Methane Emissions

The CH_4 emissions from coal bed methane (CBM) in the base cases were based the average annual CH_4 emitted (between 2002 and 2006) per short ton coal produced at the Galatia mine (EPA, 2008b). The average value, 360 standard cubic feet (scf)/ton coal, assumed all CH_4 released from the coal bed was emitted to the atmosphere. However, some coalmines have begun to incorporate a CBM recovery process, which captures CH_4 to either sell as a co-product or create on-site energy generation. EPA estimates that 20-60 percent of liberated CH_4 could be recovered using these processes (EPA, 2008b). Therefore, sensitivity analysis was performing assuming a 40 percent CH_4 recovery (216 scf CH_4/ton coal emitted) during Stage #1 of both cases. In addition, the CH_4 emissions reported for the Galatia mine between 2002 and 2006 range from 238 to 464 scf/ton. Considering the calculated standard deviation of 90 scf/ton, a high-emission case was run at 450 scf/ton to determine the total GWP when emissions were higher than the base case.

Figure 3.0-18 shows the total GWP for the total LC of both ICGG facilities assuming base, low, and high CH_4 emissions during coal mining (Stage #1). As expected, increasing CH_4 emissions increases the GWP potential for both cases (with and without CCS) by 9.6 and 1.9 percent, respectively. When considering the total LC emissions, the largest benefit associated with CH_4 recovery is seen for the IGCC with CCS, which a 15 percent reduction in GWP. When considering IGCC without CCS, the large impact from CO_2 emissions reduces the total impact of CH_4 reduction to 3 percent.

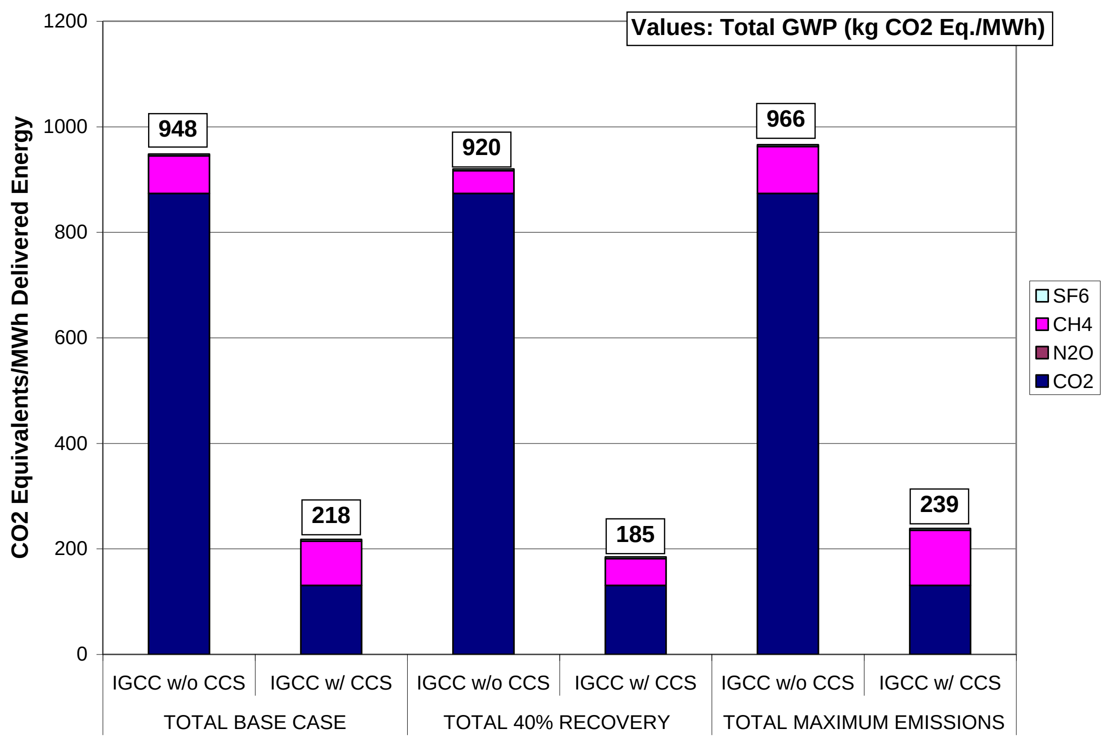

Figure 3.0-18 Analysis of Methane Recovery on GWP (kg CO2e/MWh Delivered Energy)

3.5.2.3 Rail Transport

In the base cases, coal was transported from the mine to the IGCC facility via rail a round-trip distance of 1170 miles. In order to determine the impact of raw material transport (Stage #2) on the overall LC, the rail distance was reduced to zero and total LC emissions were calculated. **Table 3-18** summarizes sensitivity of emissions to rail distance for both IGCC with and without CCS. Overall, rail distance does have a slight impact on total GWP, with a decrease of 4.4 and 7.5 percent for the without and with IGCC cases, respectively. This is mainly due to less CO_2 emissions as a result of no diesel fuel use. The sensitivity of rail distance to GWP is much larger than the increase in construction materials.

Table 3-18: Rail Distance Sensitivity on Total GHG Emissions (kg CO_2e) and Air Emissions (kg)/ MWh Delivered Energy

Emissions	Total Base Case-1170 Miles		Total - 0 Miles		% Decrease	
	IGCC w/o CCS	IGCC w/ CCS	IGCC w/o CCS	IGCC w/ CCS	IGCC w/o CCS	IGCC w/ CCS
GWP (kg CO_2e/MWh Delivered Energy)						
CO_2	873.7	130.7	860.3	115.0	1.5%	12.0%
N_2O	1.2E-01	1.4E-01	2.0E-02	2.9E-02	82.9%	80.1%
CH_4	71.1	83.8	42.4	83.2	40.3%	0.7%
SF_6	3.3	3.3	3.3	3.3	0.0%	0.0%
Total GWP	948.2	217.9	906.0	201.4	4.4%	7.5%
Non-GHG Air Emissions (kg/MWh Delivered Energy)						
Pb	1.4E-05	1.7E-05	1.3E-05	1.7E-05	0.8%	0.8%
Hg	2.6E-06	3.0E-06	2.6E-06	3.0E-06	0.4%	0.4%
NH_3	5.1E-04	6.1E-04	2.8E-05	3.4E-05	94.5%	94.3%
CO	4.7E-02	5.8E-02	8.7E-03	1.3E-02	81.6%	78.1%
NO_X	2.8E-01	2.9E-01	2.5E-01	2.5E-01	12.8%	14.6%
SO_X	8.0E-02	7.9E-02	7.3E-02	7.0E-02	9.1%	11.0%
VOC	3.7E-03	4.4E-03	3.6E-04	4.9E-04	90.2%	88.9%
PM	7.7E-02	9.0E-02	3.3E-02	3.8E-02	57.2%	57.5%

For non-GHG emissions, the largest decreases are seen graphically in **Figure 3.0-19** for NO_X, PM, and CO. Although NH_3 shows large decreases in **Table 3-18**, it contributes a small amount in the base cases when compared to the other emissions. In **Figure 3.0-19**, VOC emissions go from visible to non-visible due to the decreases. All of these emissions are dominated by the combustion of diesel fuel, which is reduced to zero in this stage with no rail travel. Overall, rail distance has a much larger impact on emissions than construction material, giving further indication that combustion, along with gasification, are the main contributors to the overall LC emissions for an IGCC facility, with and without CCS. Finally, these results indicate that raw material transport, although not usually considered a large factor during the LC of electricity generation, can have a measurable impact on the overall LCI results.

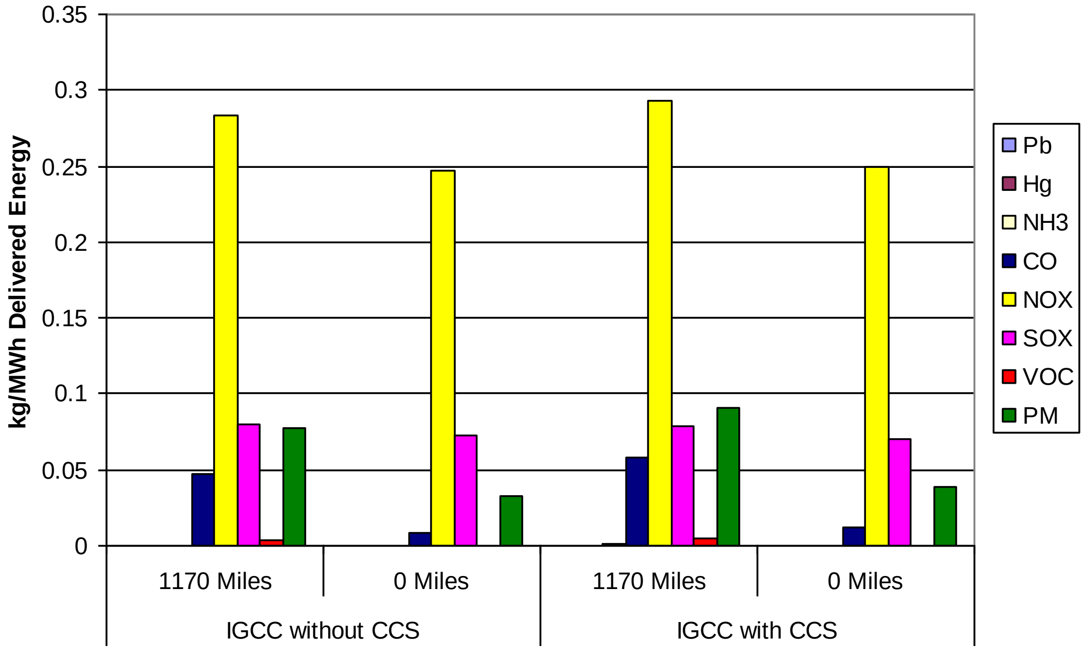

Figure 3.0-19 Distance Sensitivity on Air Emissions, kg/MWh Delivered Energy

4.0 Summary

The addition of CCS to an IGCC facility reduces LC GHG emissions by approximately 77 percent. However, adding CCS increases the LCOE by 36 percent, from approximately $0.12/MWh to $0.16/MWh of delivered electricity. Although the increase occurred for all cost parameters (capital, O&M, labor, etc.), capital cost had the largest increase at 32 percent. This indicates that advancements in CCS technologies that reduce the capital investment would most significantly reduce the overall cost differences between the two cases. Other tradeoffs from the addition of CCS included more water and land use. Approximately 23 percent more water is needed during the carbon capture process. This result suggests that depending on the location of the IGCC plant, CCS may not be practical due to limited water supply. Additional land use is needed to install the CO_2 pipeline, which is assumed to impact forestland. Little impact was seen on non-GHG air emissions due to the addition of CCS; only minor increases were calculated due to additional coal needs for Case 2 (NETL, 2010). Investors and decision makers can use the results presented in this report to weigh the benefits of carbon mitigation to the additional cost of investing in CCS technology. Additionally, these results suggest that investment in research and development (R&D) to advance CCS technologies and lower capital investment costs will have a positive effect on reducing the difference in LCOE between the cases. Finally, these results show promise in the future of coal-gasification based electricity generation with CCS.

Sensitivity analysis was performed on several cost and environmental inventory parameters. For LCC, variation in capital costs had the largest impact on LCOE, indicating that investors will need to take care when analyzing capital cost parameters for a given IGCC plant. O&M, labor, and taxes had less that a five percent impact in LCOE when parameters were varied for sensitivity. Feedstock and utility costs had a very small impact on LCOE; varying from the AEO reference case to the high price case results in only a 0.3 percent change (EIA, 2008). Therefore, although these results are based on AEO 2008, one can assume that the differences between 2008 and future AEO values will have a small impact on the overall results unless extremely large changes in feedstock and utilities prices are projected.

Sensitivity on environmental parameters was performed on CH_4 emissions from coal mining, train transport distance, and construction material inputs into Stage #1 and Stage #3. Increasing construction material inputs by 3 times the base case values has minimal impact on GHG emissions. For non-GHG emissions some impact was seen on CO and SO_X emissions, but overall this sensitivity analysis showed that material inputs have little effect on the environmental LCI. Varying the CH_4 emissions to a maximum value (based on the average of historic [2002-2006] Galatia Mine data) resulted in a GWP of 9.6 and 1.9 percent for the with and without CCS cases, respectively (EPA, 2008b). The GWP for case 2 (with CCS) decreased by 15 percent when CH_4 emissions were reduced by assuming a 40 percent recovery at the coalmine. However, this analysis does not consider other LC benefits or disadvantages associated with the recovery process, so additional modeling would need to be done before a conclusion can be drawn about its overall effectiveness. For IGCC without CCS, recovering CH_4 emissions at the coal mine only has a 3 percent impact on total GWP due to the large amount of CO_2 emitted during coal gasification. Rail transport distance did impact both GHG and non-GHG air emissions. Omitting rail transport (by cutting the distance between the mine and the IGCC facility from 1170 to 0 miles) decreased GWP by 4.4 and 7.5 percent for the without and with CCS cases, respectively. Significant decreases were also seen in total emission of NO_X, CO, and PM. The results of this sensitivity analysis validate the inclusion of raw material transport when considering the LCI impacts of a large energy conversion facility.

5.0 Recommendations

Based on the results from this study the following recommendations are made for consideration during future LCI&C studies:

- Comparison of the results in the present study to other existing and advanced electricity generation technologies would provide more insight into overall life cycle environmental and economic benefits/tradeoffs between several options.
- Detailed analysis of the quantity and type of water resources available to the energy conversion facility would add insight into the ability to retrofit or build with CCS technology. If water is available at a higher cost, the consideration of this during LCC may add further insight.
- Detailed cost analysis of fuel production (upstream of the energy conversion facility) would add value to the LCC and provide a clear distinguish between LCOE for the plant and life cycle LCOE. This type of detail could be used to verify (or disprove) the sensitivity analysis result that fuel/feedstock prices have little impact on the overall LCC.
- Inclusion of specific data for the carbon sequestration (i.e., injection) components would add value to the power generation cases with CCS.
- Little impact was seen from the inclusion of the CO_2 pipeline installation, deinstallation, and operations. The identification of a specific sequestration location, and distance from the power facility, would verify (or disprove) the LC contributions of the pipeline. Additionally, knowing the capacity of the sequestration site may indicate that, in future studies, more than one sequestration location will need to be utilized throughout the study period.
- Extending the present LCI&C to include cases with methane recovery system at the coalmine. Different mines and coal types have different levels of gassiness, and there are different end-use profiles (on-site electricity generation versus being piped to a customer). An LCI with LCC would help to draw a conclusion on its effectiveness.
- Based on sensitivity analysis, uncertainty in data quality for material inputs during construction has a minimal impact on air emissions, even with an increase of three times the base case assumptions. For future LCI&C studies, secondary LCI profiles for materials should be checked for accuracy to further verify sensitivity results. If the impacts are still minimal, one may conclude that less certainty is acceptable for material quantities used during construction.
- Results from this study validate the inclusion of raw material transport in future LCI&C studies.

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